M E M O R A N D U M

TO: Workshop Attendees

FROM: Warren Wood

SUBJECT: Record of Presentations – 2005 Energy Policy Act's New PURPA Sec. 111(d) Standards for Electric Utilities

DATE: March 8, 2006

Thank you for attending the Commission's workshop on **2005 Energy Policy Act's New PURPA Sec. 111(d) Standards for Electric Utilities**, which was held in Jefferson City, Missouri on Monday, March 6, 2006. As promised, a compendium of the materials presented has been made available on our website at http://psc.mo.gov/electric.asp.

Our desire is to make our meetings as informative, beneficial and effective as possible. Any ideas or suggestions you may have to help us achieve this are always appreciated. Feel free to contact me at 573-751-2978 or e-mail me at warren.wood.@psc.mo.gov with any comments. We look forward to you attendance and active participation in future meetings that are of interest to you.

Compendium of Workshop Materials
Table of Contents

2005 Energy Policy Act's
New PURPA Sec. 111(d) Standards for Electric Utilities

1. WORKSHOP AGENDA

Commissioners

JEFF DAVIS
Chairman

CONNIE MURRAY

STEVE GAW

ROBERT M. CLAYTON III

LINWARD "LIN" APPLING

Missouri Public Service Commission

POST OFFICE BOX 360
JEFFERSON CITY MISSOURI 65102
573-751-3234
573-751-1847 (Fax Number)
http://www.psc.mo.gov

WESS A. HENDERSON
Executive Director

DANA K. JOYCE
Director, Administration

ROBERT SCHALLENBERG
Director, Utility Services

WARREN WOOD
Director, Utility Operations

COLLEEN M. DALE
Secretary/Chief Regulatory Law Judge

KEVIN A. THOMPSON
General Counsel

TO: Interested Persons and Parties

FROM: Warren Wood, Director – Utility Operations WW 2/22/06

RE: 2005 Energy Policy Act's New PURPA Sec. 111(d) Standards for Electric Utilities Workshop, Governor Office Building Room 470, Jefferson City, Missouri Monday, March 6, 2006 – 10:00AM to 5:00PM

DATE: February 22, 2006

The Staff of the Missouri Public Service Commission invites you to attend and participate in this workshop. Participation by all regulated electric utilities is strongly encouraged.

The Energy Policy Act of 2005 ("2005 EPAct") establish five new standards in Section 111(d) of the Public Utility Regulatory Policies Act of 1978 ("PURPA") to encourage efficient use of energy, the development of renewable energy, and bringing distributed generation onto the electric grid.

- EPAct Section 1251 – Net Metering and Additional Standards
  - PURPA Sec. 111(d)(11) Net Metering
  - PURPA Sec. 111(d)(12) Fuel Sources (Fuel Diversity)
  - PURPA Sec. 111(d)(13) Fossil Fuel Generation Efficiency
- EPAct Section 1252 – Smart Metering – PURPA Sec. 111(d)(14) Time-based Metering and Communications
- EPAct Section 1254 – Interconnection – PURPA Sec. 111(d)(15)

2005 EPAct sets out these regulatory standards for state utility commissions to consider and then determine whether they are appropriate to implement. It also establishes deadlines for the consideration and determination of the applicability of the new PURPA standards.

The Staff has reviewed these provisions and wishes to convey to interested parties its interpretation of what is required of the Missouri Commission. Although this Commission has arguably dealt with most, if not all, of these issues in some fashion in the past, we need to be thinking about whether enough has been done. The Staff will be seeking your thoughts and suggestions regarding these matters during the workshop.

There is no registration fee for participation in this workshop. However, in order to better plan the workshop and accommodate participants, please register in advance. You may register by phone or email.

Susan Sundermeyer, 573-751-4113, susan.sundermeyer@psc.mo.gov

or

Ashley Harrison, 573-751-4568, ashley.harrison@psc.mo.gov

Workshop Agenda for
2005 Energy Policy Act's
New PURPA Sec. 111(d) Standards for Electric Utilities
Monday, March 6, 2006 – 10:00am to 5:00pm
Governor Office Building Room 470

9:30	**Registration**
10:00	**1. Opening Remarks and Introductions** – Staff - Warren Wood, Director - Utility Operations
	1.1. Welcome – Chairman Jeff Davis
	1.2. Post-workshop compendium will be posted at http://psc.mo.gov/electric.asp
	1.3. If you wish to be added to the mailing list, please provide your name and either an email or mailing address
	1.4. Introductions
	1.5. Significance of the issues to be addressed – Staff – Mike Proctor, Chief Economist
10:15	**2. 2005 EPAct – The New Standards and Timelines** – Staff - Carmen Morrissey, Policy Analyst
	2.1. EPAct Section 1251 – Net Metering & Additional Standards
	2.1.1. PURPA Sec. 111(d)(11) Net Metering
	2.1.2. PURPA Sec. 111(d)(12) Fuel Sources (Fuel Diversity)
	2.1.3. PURPA Sec. 111(d)(13) Fossil Fuel Generation Efficiency
	2.2. EPAct Section 1252 – Smart Metering - PURPA Sec. 111(d)(14) Time-based Metering and Communications
	2.3. EPAct Section 1254 – Interconnection – PURPA Sec. 111(d)(15)
10:45	**3. Available Smart Metering Technology and Costs** – KCPL - George Phillips, Manager of Commercial & Industrial
11:15	**Lunch** (1 hour) – on your own
	4. Relevant Prior State Actions and Compliance
	4.1. PURPA Sec. 111(d)(14) Time-based Metering & Communications
12:15	**4.1.1.** Staff - Dan Beck, Supervisor - Engineering Analysis
12:40	**4.1.2.** Utilities – AmerenUE - John Luth, Manager of System Metering and Michael Whitmore, Engineer-Resource Planning
1:00	**4.1.3.** Others' views as to what is needed for compliance
	4.2. PURPA Sec. 111(d)(15) Interconnection & PURPA Sec. 111(d)(11) Net Metering
1:30	**4.2.1.** Staff - Warren Wood, Director - Utility Operations
1:45	**4.2.2.** Utilities – Empire Electric – Bill Eichman, Manager of Industrial and Commercial Energy Services
2:00	**4.2.3.** Others' views as to what is needed for compliance

Workshop Agenda for
2005 Energy Policy Act's
New PURPA Sec. 111(d) Standards for Electric Utilities
Monday, March 6, 2006 – 10:00am to 5:00pm
Governor Office Building Room 470

4.3. PURPA Sec. 111(d)(12) Fuel Sources (Fuel Diversity) & PURPA Sec. 111(d)(13) Fossil Fuel Generation Efficiency

2:15 **4.3.1.** Staff - Lena Mantle, Manager - Energy Dept.

2:25 **4.3.2.** Utilities – Empire Electric - Brad Beecher, Vice President - Energy Supply

2:35 **4.3.3.** Others' views as to what is needed for compliance

2:45 **Break** (15 min.)

3:00 **5. Procedural Alternatives for Meeting Statutory Requirements – Roundtable Discussion** – Staff - Lena Mantle, Manager - Energy Dept.

5.1. Initiate rulemaking docket(s)? Address in individual rate cases? Need for pilots?

5.2. Others' views and ideas.

4:30 **6. Closing Remarks**

<u>Reference Materials</u> – currently posted at http://psc.mo.gov/energypolicyworkshop.asp

- Excerpts from 2005 Energy Policy Act – Sections 1251, 1252 and 1254
- Public Utility Regulatory Policies Act of 1978 (with 2005 EPAct changes red-lined)
- 11/21/05 Staff Discussion of 2005 EPAct Smart Metering Requirements
- 3/1/06 Staff's Supplemental Information Regarding 2005 EPAct Sections 1251 and 1254
- 4 CSR 240-20.065 Net Metering
- 4 CSR 240-22 Electric Utility Resource Planning

2. Presentations

Newly Formed Wholesale Electricity Markets Should Cause Us To Rethink Demand Response In Terms of “Shortage Pricing”

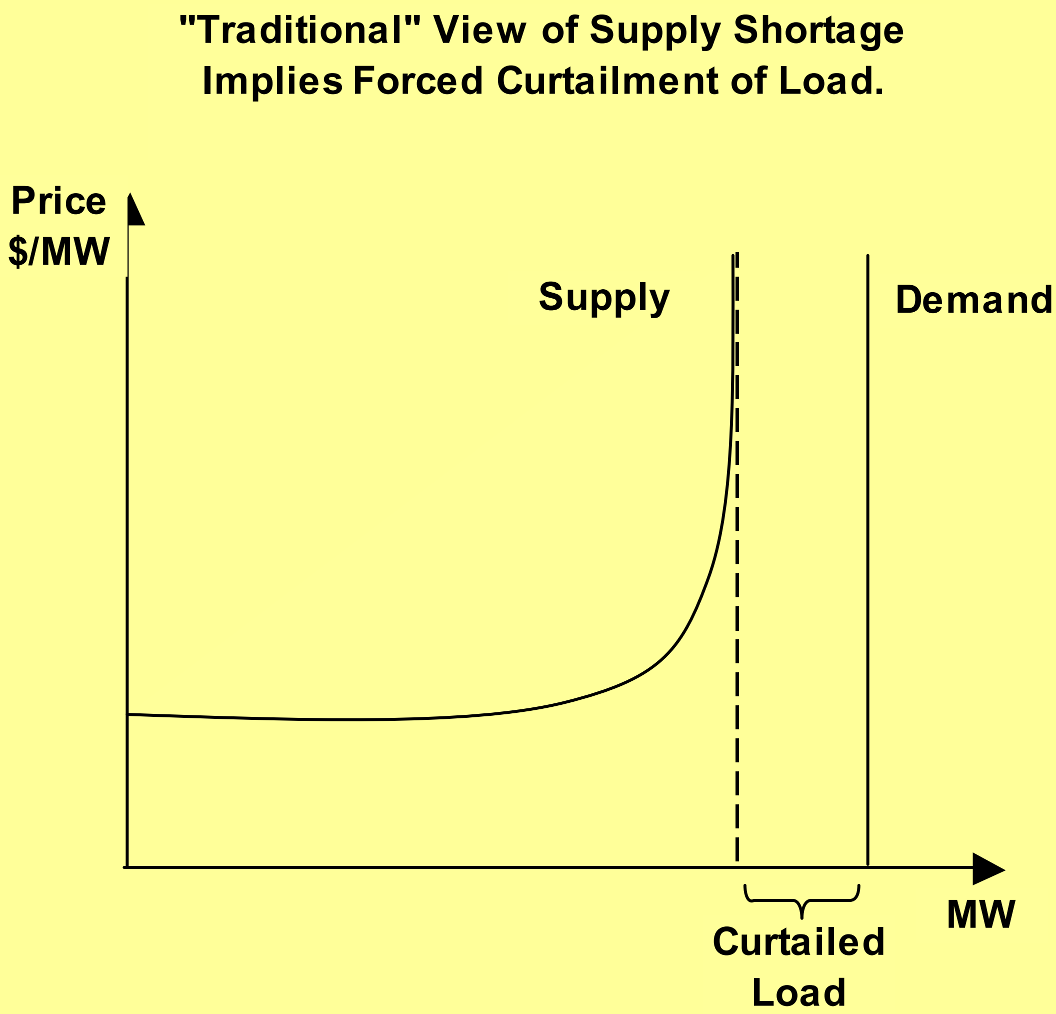
by

Michael S. Proctor

Chief Economist

Missouri Public Service Commission

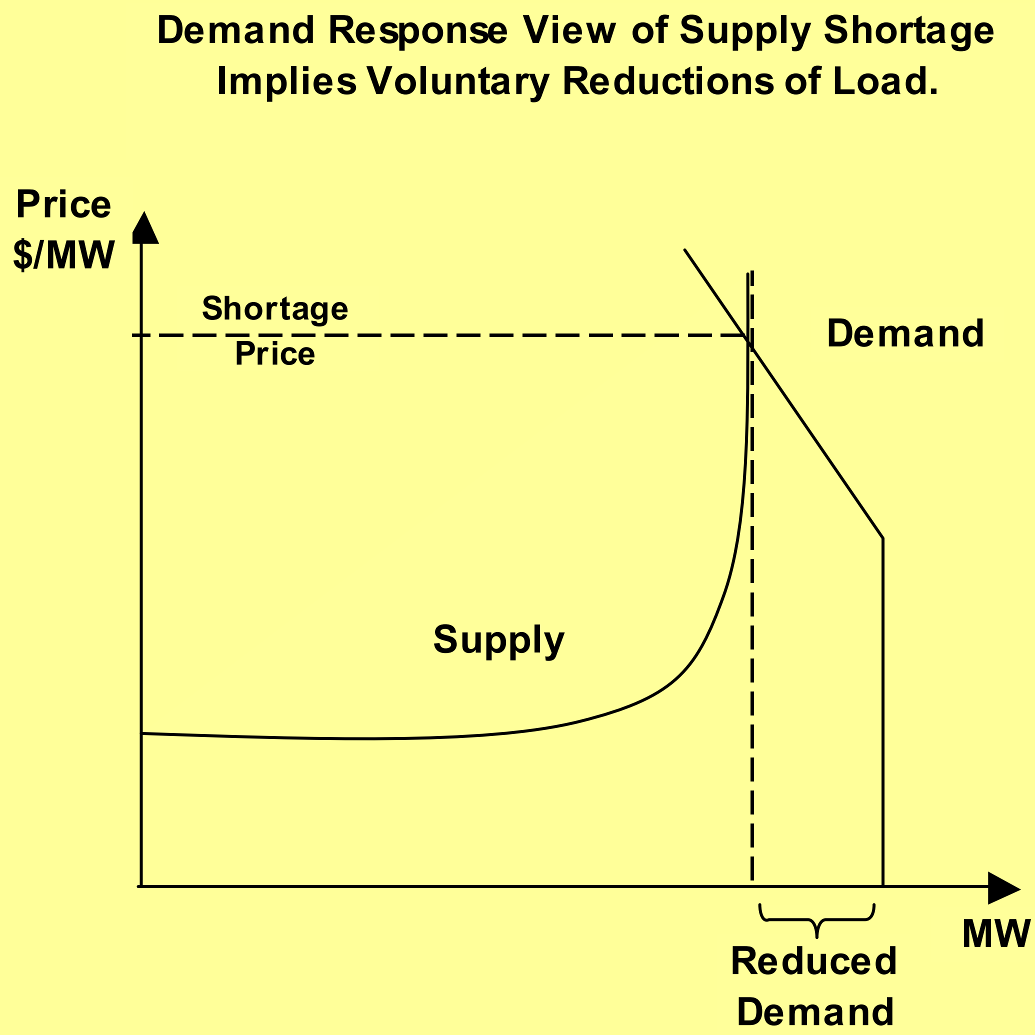
Traditional View of Supply Shortages



Some Implications from Traditional View of Supply Shortages

- Forced curtailments are extremely costly to society.
- Forced curtailments rarely allow for discrimination based on the cost to society.
  - Missouri IOU tariffs have set some priorities.
- Forced curtailments should be avoided through planning reserve requirements.
  - NERC/RRO reliability criteria of 1 day in 10 years.
- "Society" ends up paying the cost either
  a. For "arbitrarily" high reliability standards; or
  b. For force curtailments when there is a supply shortage.

Demand Response View of Supply Shortages



Some Implications from Demand Response View of Supply Shortages

- Voluntary curtailment of electricity usage allows the curtailments to be based on the costs to the customers from reducing demand.
- If the price offered is high enough, customers will voluntarily curtail demand, and with increasingly high prices being offered, increasing amount of curtailed demand will be offered.
- Load-serving entities short of supply will pay the cost of supply shortages, not "society."

What We Need to Rethink

- From a policy perspective, which view (traditional vs. demand response) makes the most sense?

  SHOW OF HANDS

- Should we hold workshops to determine how to design and implement demand response for shortage pricing?

  SHOW OF HANDS

Thank You for Listening.

Have a Good Workshop!

Workshop on
2005 Energy Policy Act
New PURPA Section 111(d) Standards for Electric Utilities

The New Standards and Timelines

Carmen Morrissey, CPA
Missouri Public Service Commission
Energy Dept. - Utility Policy Analyst II
573-751-7531
c.morrissey@psc.mo.gov

March 6, 2006

The Energy Policy Act of 2005 (EPAct)

- effective date August 8, 2005
- Title XII-E Amends PURPA (Public Utility Regulatory Policies Act of 1978)
- PURPA's general objective is to increase conservation of electric energy and increase efficiency in use of facilities and resources

Relevant excerpts from 2005 EPAct and PURPA with 2005 EPAct changes red-lined are currently at **http://psc.mo.gov/energypolicyworkshop.asp**

PURPA - key provisions relative to state retail electric utilities

- Sec. 111(a) & (c) – require a determination as to <u>whether or not it is appropriate</u> to implement each standard
- Sec. 111(d) – suggested standards for electric utilities
- Sec. 112 – obligations for consideration and determinations by state commissions and non-regulated utilities, including
  - deadlines
  - failure to comply
  - exemption for prior state actions
- Sec. 115 – special rules for standards (new provisions relative to time-based metering and communications)

PURPA - five new standards to be considered for electric utilities

- EPAct Sec. 1251 – Net Metering and Additional Standards
  - PURPA Sec. 111(d)(11) Net Metering
  - PURPA Sec. 111(d)(12) Fuel Sources (Fuel Diversity)
  - PURPA Sec. 111(d)(13) Fossil Fuel Generation Efficiency
- EPAct Sec. 1252 – Smart Metering
  - PURPA Sec. 111(d)(14) Time-Based Metering and Communications
- EPAct Sec. 1254 – Interconnection
  - PURPA Sec. 111(d)(15) Interconnection

EPAct Deadlines

for Consideration and Determination of New PURPA Standards

	By 8/8/06	By 8/8/07	By 8/8/08	
Smart Metering PURPA Sec. 111(d)(14)	commence consideration PURPA Sec.112(b)(4)(A)	complete determination PURPA Sec.112(b)(4)(B)		However, it should be noted PURPA Sec. 111(d)(14)(F) indicates state commissions shall issue a decision re: implementation by 2/8/07.
Interconnection PURPA Sec. 111(d)(15)	commence consideration PURPA Sec.112(b)(5)(A)	complete determination PURPA Sec.112(b)(5)(B)		
Net Metering PURPA Sec. 111(d)(11)		commence consideration PURPA Sec.112(b)(3)(A)	complete determination PURPA Sec.112(b)(3)(B)	
Fuel Diversity PURPA Sec. 111(d)(12)		commence consideration PURPA Sec.112(b)(3)(A)	complete determination PURPA Sec.112(b)(3)(B)	
Fossil Fuel Efficiency PURPA Sec. 111(d)(13)		commence consideration PURPA Sec.112(b)(3)(A)	complete determination PURPA Sec.112(b)(3)(B)	

EPAct Deadlines

for Consideration and Determination of New PURPA Standards

- Sec. 112(c) Failure to Comply
  - If the determination deadline for any of the new standards is **not** met, consideration and determination regarding that standard shall be addressed in the first rate proceeding commenced after August 8, 2008.

PURPA Sec. 111(d)(14)
? Time-Based Metering and Communications ?

- Shall utilities be required to -
  - offer each of its customer classes certain time-based rate schedules,

    and

  - provide individual customers, upon request, with a time-based meter capable of enabling time-based service and rates?
    - Sec. 115(i) ---and enable other demand response programs?

PURPA Sec. 111(d)(14)

? Time-Based Metering and Communications ?

- If so, types of time-based rate schedules that may be offered, among others, are:
  - time-of-use pricing
  - critical peak pricing
  - real-time pricing
  - credits for consumers with large loads

- If so, the time-based rates shall be determined to be cost-effective (i.e. long-run benefits of such rate to the utility and its consumers are likely to exceed the costs associated with the use of such rates). Sec. 115(b)

PURPA Sec. 111(d)(15) ? Interconnection ?

- Shall utilities be required, upon request, to connect on-site customer generation to their distribution systems?

- If so, service, procedures and agreements shall -
  - promote current best practices of interconnection for distributed generation,

    and
  - be just and reasonable, and not unduly discriminatory or preferential.

PURPA Sec. 111(d)(11)
? Net Metering ?

- Shall utilities be required to make available, upon request, net metering services?
  - allowing energy to be delivered to the utility’s system
  - from eligible on-site customer generation
  - to offset the energy the utility provides to that customer

PURPA Sec. 111(d)(12)
? Fuel Sources (Fuel Diversity) ?

- Shall utilities be required to develop a plan
  - to minimize dependence on one fuel source,

    and

  - to ensure that the electric energy it sells is generated using a diverse range of fuels and technologies, including renewables?

PURPA Sec. 111(d)(13) ? Fossil Fuel Generation Efficiency ?

- Shall utilities be required to develop and implement a 10-year plan to increase the efficiency of its fossil fuel generation?

PURPA Sec. 112(d)(e)&(f) Exemptions for prior state actions, if ---

- the State has implemented a comparable standard,
- the state commission or relevant non-regulated electric utility has conducted a proceeding to consider implementation of a comparable standard,

or

- the state legislature has voted on the implementation of a comparable standard

---

Note: the prior state action relative to Sec. 111(d)(14) Time-Based Metering is to have been within the previous 3 years

PURPA Procedural Requirements ------Other than deadlines continued…

- Sec. 111(a) CONSIDERATION AND DETERMINATION.

  Each State regulatory authority (with respect to each electric utility for which it has rate-making authority) and each non-regulated electric utility shall consider each standard established by subsection (d) and make a determination concerning whether or not it is appropriate to implement such standard to carry out the purposes of this title. … Nothing in this subsection prohibits any State regulatory authority or non-regulated electric utility from making any determination that it is not appropriate to implement any such standard, pursuant to its authority under otherwise applicable State law.

PURPA Procedural Requirements ------Other than deadlines continued…

- Sec. 111(b) PROCEDURAL REQUIREMENTS FOR CONSIDERATION AND DETERMINATION.
  - (1) The consideration referred to in subsection (a) shall be made after public notice and hearing. The determination referred to in subsection (a) shall be—
    - (A) in writing,
    - (B) based upon findings included in such determination and upon the evidence presented at the hearing,

      and
    - (C) available to the public.

PURPA Procedural Requirements ---
---Other than deadlines continued…

- Sec. 111(c)IMPLEMENTATION
  - (2) If a State regulatory authority (with respect to each electric utility for which it has ratemaking authority) or non-regulated electric utility <u>declines to implement any standard</u> established by subsection (d) which is determined under subsection (a) to be appropriate to carry out the purposes of this title, <u>such authority or non-regulated electric utility shall state in writing the reasons therefore</u>. Such statement of reasons shall be available to the public.

PURPA Procedural Requirements ------Other than deadlines continued…

- Sec. 112. OBLIGATIONS TO CONSIDER AND DETERMINE.
  - (a) REQUEST FOR CONSIDERATION AND DETERMINATION.--Each State regulatory authority (with respect to each electric utility for which it has ratemaking authority) and each non-regulated electric utility may undertake the consideration and make the determination referred to in section 111 with respect to any standard established by section 111(d) in any proceeding respecting the rates of the electric utility.

    Any participant or intervenor (including an intervenor referred to in section 121) in such a proceeding may request, and shall obtain, such consideration and determination in such proceeding.

continued…

PURPA Procedural Requirements ------Other than deadlines

…continued

- Sec. 112(a) REQUEST FOR CONSIDERATION AND DETERMINATION.—
  - In undertaking such consideration and making such determination in any such proceeding … , a State regulatory authority (with respect to an electric utility for which it has ratemaking authority) or non-regulated electric utility <u>may take into account</u> in such proceeding—
    - (1) any appropriate prior determination with respect to such standard,

      and
    - (2) the evidence upon which such prior determination was based (if such evidence is referenced in such proceeding).

The Energy Policy Act of 2005 (EPAct)

- Other Reference Resources
  - FERC (Federal Energy Regulatory Commission)
    - http://www.ferc.gov/legal/maj-ord-reg/fed-sta/ene-pol-act.asp
  - U.S. DOE (Dept. of Energy)
    - http://www.electricity.doe.gov/program/electric_oa_policy_energy_epacthome.cfm?section=divisions&level2=oandm_policy_energy
  - Demand Response and Advanced Metering Coalition
    - http://www.dramcoalition.org/

Available Smart Metering Technology and Costs

George Phillips, P.E.
Manager of Commercial and Industrial Markets
Kansas City Power & Light
March 6, 2006
Missouri PSC Workshop
Energy Policy Act 2005

EPACT 2005
Sec. 1252. Smart Metering

- Encourages time-based rates
  - Time-of-Use
  - Critical Peak Pricing
  - Peak Load Reduction

KCP&L – TOU and RTP

- Time-of-Use
  - Market - Residential
  - 110 customers
  - Uses TOU meters that are read in the field
- Real Time Price
  - Market – Medium and large C&I
  - 8 customers
  - Day-ahead hourly pricing
  - MV90 metering
    - Records energy usage and demand for billing
    - Permits customer to see current usage on the internet for good load management

KCP&L - Peak Load Curtailment Credit (PLCC)

- 1991 to present
- Market – large C&I
- 7 to 20 customers:10 in 2005
- 13 MW to 34 MW: 25 MW in 2005
- Measurement – MV90 and CellNet

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KCP&L – MPower (new)

Barrier under PLCC	Potential solution under MPower
More than three days of curtailment in a row	Maximum number of consecutive curtailment days – 3 Days
Cost of each curtailment • Costs to change production schedule ▪ Costs of generation	Curtailment event incentive - $0.36/kW/event
Cost of non-compliance	One curtailment opt-out per season; Energy purchase option available at KPCL determined price (available during economic curtailments only)
No opt-out or purchase option	One curtailment opt-out per season; Energy purchase option available at KPCL determined price (available during economic curtailments only)
No program design options … no choice on anything	Choices on: • term of contract (1, 3, 5 years) • curtailment season (May-Sep or 12 months) • # of events (25 or 30) • Participation incentive (30%, 40%, 50%) Incentive type (participation, event, initial)
Capital costs that may be required to participate	Participation incentive can be taken annually or upfront (initial)

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E N E R G I Z I N G L I F E

Critical Peak Pricing

- KCP&L will study this in 2006
- Market – residential and small commercial
- Price - sharp price deferential required – 3x, 5x
- Technology - enhancements improve performance
- Input from proposed CPAG

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Direct Load Control – Technology Evaluation

	Outdoor Switch	One-Way Thermostat	Two-Way Thermostat
Description	Receives signals from the utility. Controls outside air conditioning unit.	Radio controlled programmable thermostat that receives signals from the utility. Controls ac.	Radio controlled programmable thermostat that receives signals from and sends signals back to the utility. Controls ac.
Installed Cost	$165	$300 to $325	$450 to $650
Average kW Load Reduction	0.8 to 1.1	1.2 to 1.3	1.2 to 1.3
Cost per kW	$165	$270	$460
Customer Features	$20 to $40 per home per year	Free thermostat.	Free thermostat.
		Internet programming.	Internet programming
			Can remotely "see" what the thermostat is doing via the Internet.

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Taken from 2004 E Source report

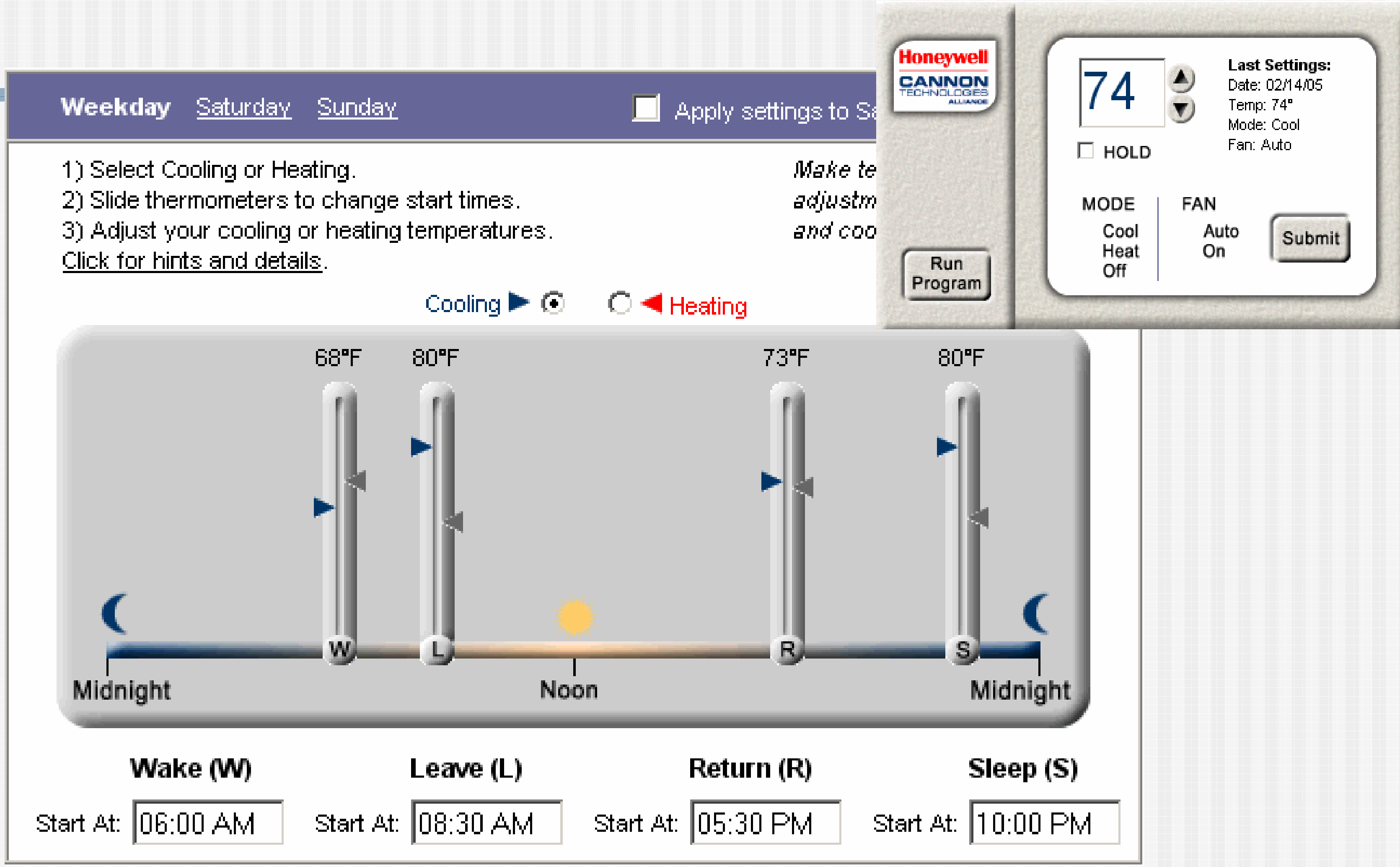
Technology Selected: One-way thermostat

- 900 MHz flex paging
- CellNet
  - Evaluation
    - Measure change in kW each hour during curtailment
    - Statistically valid random sample
    - Control and test sample
    - Summer hourly energy usage
    - Compare test sample to control sample
    - Compare to similar days
  - Verification
    - CellNet On Demand

Energy Optimizer Load Control Program (Air Conditioning Cycling)

- November 2005 to present
- 1,000 customers now: 8,000 by 7/1/2005
- 1.1 kW load reduction per customer
- Programmable thermostat – radio controlled
- Residential and small commercial
- Customer manages heat and cooling all year
- Customer can program thermostat over the Internet
- Multiple cycling strategies
- Customer can opt-out one time each month
  - By phone
  - By the Internet

Easy Internet Programming



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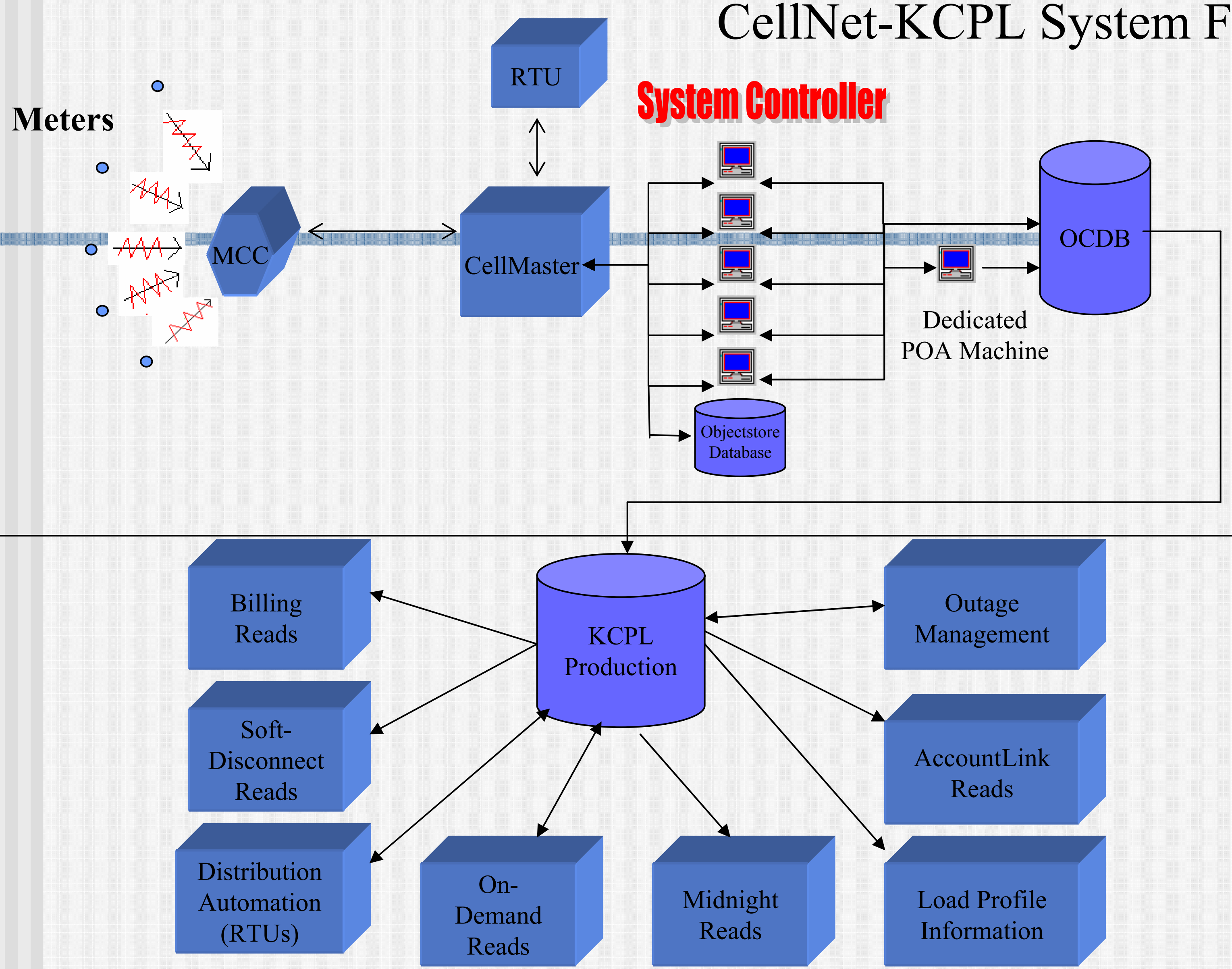
CellNet-KCPL System Flow



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Delivery System of the Future

GPE Strategic Intent

- Leadership in supplying and delivering energy solutions
- Strong operating performance and competitive asset base
- Benefit from changing market and technological innovation
- Build core strengths and add capabilities to benefit stakeholders

Delivery System of the Future

- Partner with customers to dynamically manage load shape
  - Demand response & efficiency programs
  - System automation and monitoring
- Distributed energy resources
- Real-time 2-way communication

Delivery Strategy

- Customer
- Community
- Communications
- Regulatory & Governmental
- Infrastructure & Asset Management
- Information Technology
- Transmission Services

Initiatives

- Strategic Initiatives
  - Customer focused programs
  - Infrastructure and Asset Management programs
- Ongoing Operational Initiatives
  - Regulatory
  - Community
  - Communication
  - Customer Satisfaction
  - Cost Control
  - Efficiency & Productivity
  - Process improvement

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Four key programs that are part of the Delivery System of the Future

Delivery System of the Future

- Demand Response and Efficiency Programs
- Distributed Energy Resources

- Existing programs
  - **AC Cycling**
  - **MPower**
  - Energy Efficiency
  - **RTP and TOU**
- Incremental programs
  - **Critical Peak Pricing**
  - Additional Energy Efficiency programs

- E-services

- Existing Programs
  - **AccountLink**
  - Online account maintenance
  - Automated and electronic payment
- Incremental programs
  - Web forums and instant messaging

- System Automation and Monitoring (Circuit of the Future)

- **Dynamic voltage control**
- **Switch automation**
- **Capacitor automation**
- Relay automation
- Rural power quality monitoring

- Real-time, Two-way Communication

- Fiber to substations
- Additional wireless communications
- Distribution and demand response control technologies

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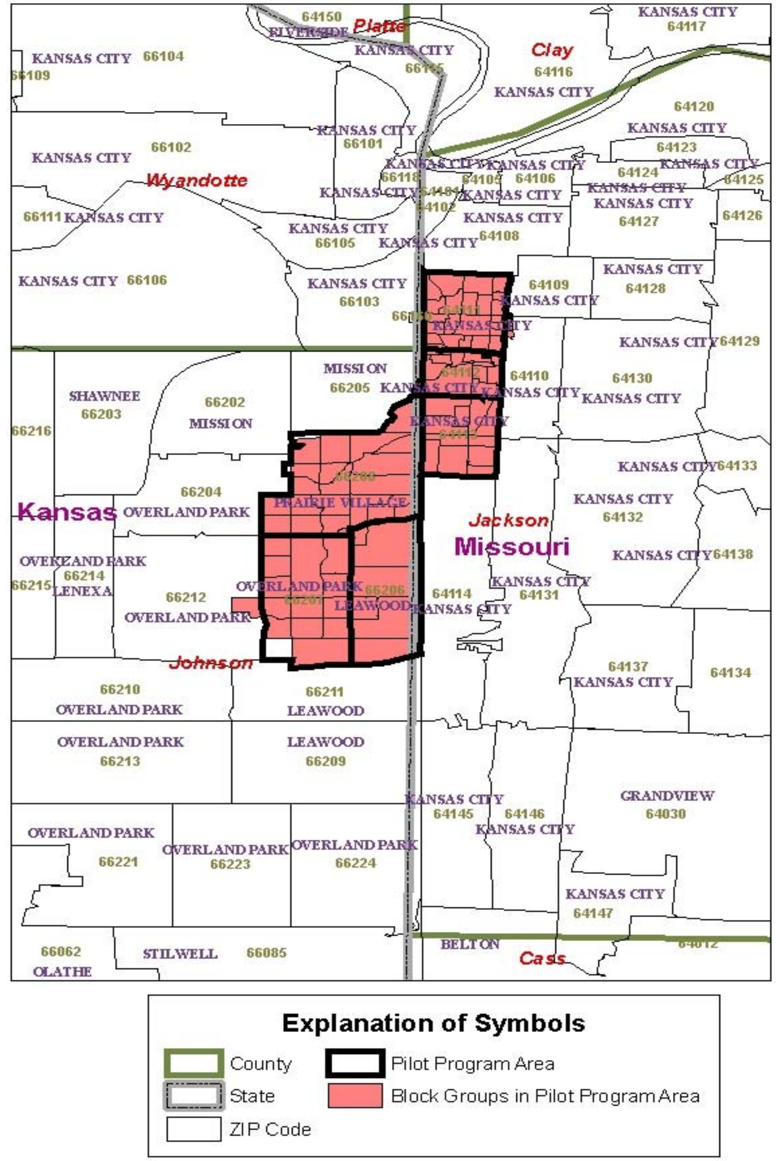
Benefits, Costs, and Risks

	Economic Benefits	Costs
▪ Demand Response and Efficiency Programs ▪ Distributed Energy Resources	▪ Energy and capacity ▪ Reserve margin and other ancillary services ▪ T&D deferral	▪ Equipment/hardware ▪ Program administration and marketing
▪ E-services	▪ Customer service efficiency ▪ Transaction and payment processing savings ▪ Reduced paper and postage	▪ IT investment ▪ Program administration and marketing
▪ System Automation and Monitoring (Circuit of the Future)	▪ Energy and capacity ▪ Reserve margin and ancillary services ▪ T&D Deferral ▪ Reduced system losses ▪ O&M cost reductions ▪ Lower bad debt write-offs	▪ Equipment ▪ Maintenance of new equipment ▪ Diagnostics and control systems ▪ Data monitoring and analysis systems
▪ Real-time, Two-way Communication	▪ Reduced dependence on communication carriers ▪ Faster and more efficient response to outages ▪ Improved safety ▪ Enables real-time pricing – reduced cost/ increased wholesale	▪ Equipment and hardware ▪ O&M expense to manage network

Example:

Using Demand Response for Distribution Load Relief

- Energy Optimizer
- Initial target market includes 5 circuits/6 zip codes



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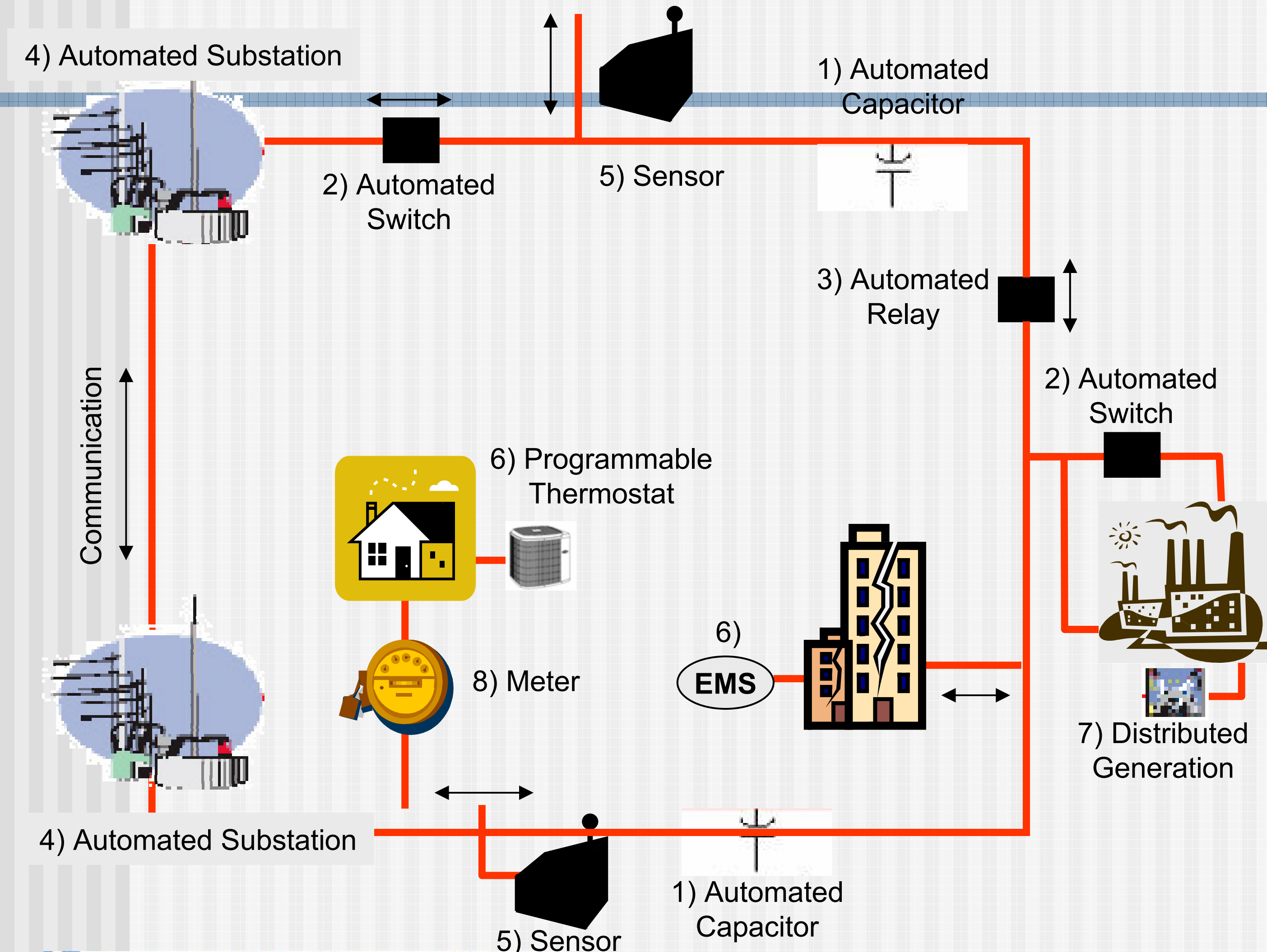
Automation and monitoring for improved system reliability and management



Circuit of the Future Plans Include:

1. Automated capacitors
2. Automated switches
3. Automated relays
4. Dynamic voltage control through automated substations
5. Power quality monitoring through sensors
6. Load control devices
   - Thermostats
   - Energy Management Systems
7. Distributed generation
8. Automated metering

Kansas City Power & Light
ENERGIZING LIFE

George Phillips
Manager of C&I Markets
Kansas City Power & Light
P.O. Box 418679
Kansas City, MO 64141-9679
Office 816-556-2648
Fax 816-654-1970
george.phillips@kcpl.com

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Glossary

•Billing Reads – Midnight On-Cycle reads, types received are cumulative and demand. (Missed reads lead to Estimated Reads)

•Soft-Disconnect Reads – Midnight Off-Cycle reads for move-in/move-outs. (Reduction of over 125,000 field trips annually)

•Distribution Automation – Used by Engineering and Dispatching for capacitor bank and switch control and monitoring. Utilizes CellNet's radio system infrastructure.

•On-Demand Reads – Used by the Customer Call Center to aid in customer calls to resolve usage issues and reduce call times and unnecessary field trips for high bill tests can be averted.

•Midnight Reads – Used company wide for analysis of customers usage

•Load Profile Information – Provides 5-minute interval metering data. Currently used by Regulatory Department for class usage analysis for rate cases and by Energy Solutions for load curtailment. Can be used for real-time pricing and time-of-use rates. Cost is roughly 15 times higher than monthly billing read pricing.

•Accountlink – Uses the midnight read capabilities to provide customers with their daily usage information. Free service.

•Outage Management – Application for "okay on arrival", outage notification, and outage restoration. Current applications for outage notification and restoration verification are integrated with our Outage Management System.

Time-Based Metering And Communications

By
Dan Beck
Engineering Analysis Supervisor
Missouri Public Service Commission

Overview

- PURPA Section 111(d)(14) Time-Based Metering And Communications
- Is this about Hardware or Rate Design?
- Hardware Sections 111(d)(14)(C) & 115(i)
- Rate Design Sections 111(d)(A) & 111(d)(B)
- Prior Related Actions by PSC & Utilities

PURPA Section 111(d)(14) Time-Based Metering And Communications

- “Section 111 (a) Consideration and Determination – Each state regulatory authority (with respect to each electric utility for which it has rate-making authority) and each nonregulated utility shall consider each standard established by subsection (d) and make a determination concerning whether or not it is appropriate to implement such standard to carry out the purposes of this title.”

Is this About Hardware or Rate Design?

- Answer: Both
- Technology: Meters, Communication Equipment and Billing Systems
- Rate Design: New technology allows for rate designs that weren’t practical when PURPA was first enacted in 1978 with 6 ratemaking standard or in 1992 when 4 additional standard were adopted

Hardware Sections 111(d)(14)(C) & 115(i)

- Subsection 111(d)(14)(C) – “Each electric utility subject to subparagraph (A) shall provide each customer requesting a time-based rate with a time-based meter capable of enabling the utility and customer to offer and receive such rate, respectively.”
- Section 111(i) – “Time-Based Metering and Communications – In making a determination with respect to the standard established by section 111(d)(14), the investigation requirement of section (111)(d)(14)(F) shall be as follows: Each State regulatory authority shall conduct an investigation and issue a decision whether or not it is appropriate for electric utilities to provide and install time-based meters and communication devices for each of their customers which enable such customers to participate in time-based pricing rate schedules and other demand response programs.”

Rate Design Sections 111(d)(A) & 111(d)(B)

- Section 111(d)(A) – Electric utility shall offer individial customers in each of its customer classes a time-based rate schedule
- Section 111(d)(B) – Examples of time-based rate schedules with descriptions of each: Time-of-Use Pricing, Critical Peak Pricing, Real Time Pricing, Credits for Consumers with Large Loads

Prior Related Actions by PSC & Utilities

- PURPA 1978 – Commission addressed first 6 sections of Section 111 in rate design or ratemaking cases. Standards were: Cost of Service, Declining Block Rates, Time-Of-Day Rates, Seasonal Rates, Interruptible Rates and Load Management Techniques
- EPAct 1992 – Commission addressed the next 4 sections of Section 111 in 1993 and determined that Commission had considered and implemented, at least in part, new standard Sections 111(d)(7), (8) and (9). The Standards were: Integrated Resource Planning, Investments in Conservation and Demand Management, Energy Efficiency Investments in Power Generation and Supply, Wholesale Power Purchase Considerations.

How to Proceed?

Types of Time-Based Rate Schedules from PURPA Section 111(d)(14)(B):

(i) Time-of-Use Pricing (Seasonal Rates, Optional Time-of-Day Rates, Mandatory Time-of-Day Rates)

Seasonal Rates

All Missouri Commission regulated electric utilities have seasonal rates that are higher in the summer months (June through September) than in the winter months (October through May).

Aquila, Inc.	Empire District	KCPL	Union Electric
P.S.C. MO No. 1	*P.S.C. MO No. 5*	*P.S.C. MO No. 7*	*P.S.C. MO No. 5*

Optional Time-of-Day Rates

All Missouri Commission regulated electric utilities offer optional time-of-day rates with higher rates on peak and lower rates off peak to all of their customers.

Aquila, Inc.	Empire District	KCPL	Union Electric
L&P- Optional Time of Use Adjustment Rider *Sheet No. 35*	Optional Time of Use Adjustment Rider, Section 4 *Sheet No. 18*	Residential Time of Day Service *Sheet No. 8*	Listed with each Rate Schedule
MPS – Time of Day Residential - No. 66 General Service *Sheet No. 67*		Non-Residential Two Part - Time of Use *Sheet No. 20*	Non- Res Secondary Service Off-Peak Demand Provisions - Rider I *Sheet No. 113*
MPS - Thermal Energy Storage Pilot *Sheet No. 70*		Incremental Energy Rider *Sheet No. 24*	

Mandatory Time-of-Day Rates

Aquila, Inc.	Empire District	KCPL	Union Electric
L&P - Large Power Service *Sheet No. 35*			

(ii) Critical Peak Pricing (Time-of-Day Rates with Critical Peak Pricing)

AmerenUE has a pilot/test program underway to determine the effectiveness of day-ahead notification of residential customers of a Critical Peak Pricing Period and the benefits of using a “smart” thermostat in conjunction with the program.

Aquila, Inc.	Empire District	KCPL	Union Electric
			Residential Time of Use Pilot *Sheet No. 192*

(iii) Real-Time Pricing

Hourly day-ahead prices are transmitted to large non-residential customers, i.e., large industrial and commercial customers, based on expected load and market conditions. These prices apply to increases and decreases in a customer's load relative its baseline load.

Aquila, Inc.	Empire District	KCPL	Union Electric
MPS - Real Time Pricing *Sheet No. 73*	Cancelled Program – No customers	Real-Time Pricing - *Sheet No. 25* RTP - Plus *Sheet No. 26*	

(iv) Credits for consumers with large loads (Interruptible/Curtailable Rates)

Customers are paid to reduce load during the highest cost hours of the summer. All Missouri Commission regulated electric utilities offer some form of interruptible/curtailable rates to large customers.

Aquila, Inc.	Empire District	KCPL	Union Electric
MPS & L&P - Voluntary[1] Load Reduction Rider *Sheet No. 96*	Interruptible[2] Rider Section 4 *Sheet No. 4*	Peak Load Curtailment[3] Rider *Sheet No. 21*	Voluntary[2] Curtailment Rider *Sheet No. 116*
MPS & L&P - Curtailable[3] Demand Rider - *Sheet No. 99*		Voluntary[2] Load Reduction Rider *Sheet No. 27*	Option Based Curtailment Rider[3] *Sheet No. 116.3*

[1] Under these programs, the customer is offered a price per kWh to reduce its load during the curtailment period, and the customer may either accept or reject the offer.

[2] Under these programs, the customer receives a credit per kW of curtailable demand and must reduce load whenever a curtailment is called.

[3] This is a hybrid. Under this program, the customer receives an "Option Premium Payment" per MW of curtailable demand and a $/MWh "Strike Price" payment for each MWh of load reduction. If the customer fails to reduce load to the agreed level when a curtailment is called, the customer must pay the Company the "Passthrough Market Price" for each MWh it uses in excess of the contracted level.

2005 Energy Policy Act
Standards For Electric Utilities
MPSC Workshop

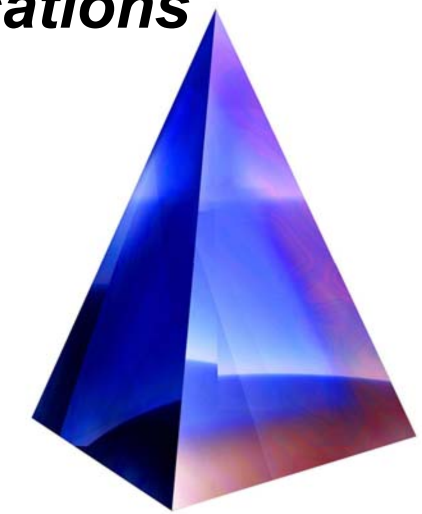
Time-Based Metering & Communications

Experiences at AmerenUE

March 6, 2006

John Luth

Mike Whitmore



Time-Based Metering

AmerenUE utilizes a variety of time-based metering.

The Automated Meter Reading system supports time-based metering, within limits.

Agenda

- **Summary of Time-based Metering**
- AMR – Technology Overview
- AMR – Time-based Meter Readings
- AMR – Capabilities & Limits
- AmerenUE's Existing Electric TOU Tariffs
- Critical Peak Pricing Pilot
- Preliminary Results

AmerenUE

Summary of Time-based Metering

READING METHOD	READING TYPE	NUMBER OF METERS
Automated Meter Reading (AMR)	Consumption	1,178,512
	Demand	13,976
	TOU	1,816
	Interval TOU	1,055
Phone lines	Interval TOU	31
	Total:	1,195,359
	TOU based:	2,902

Nearly all of AmerenUE's 1.2 million electric customers are read with AMR. The vast majority are on a consumption-only rate.

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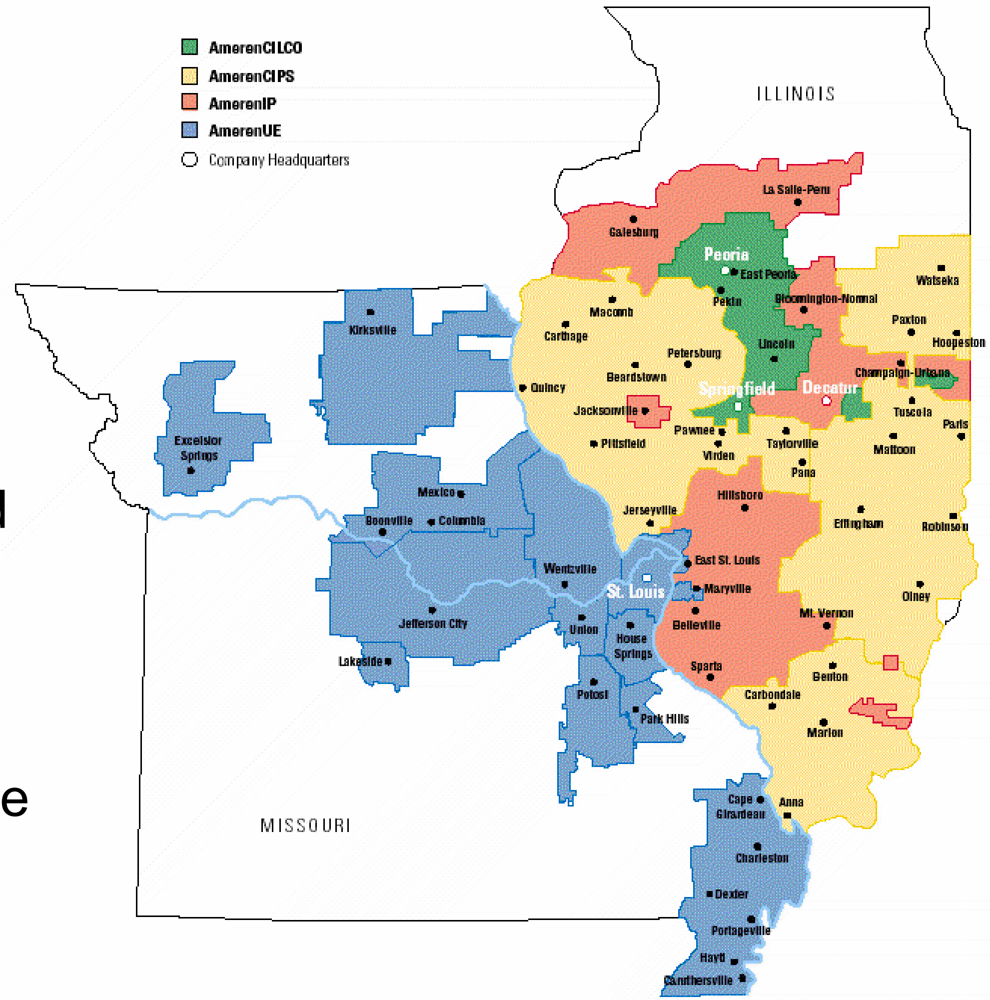
AmerenUE's AMR system

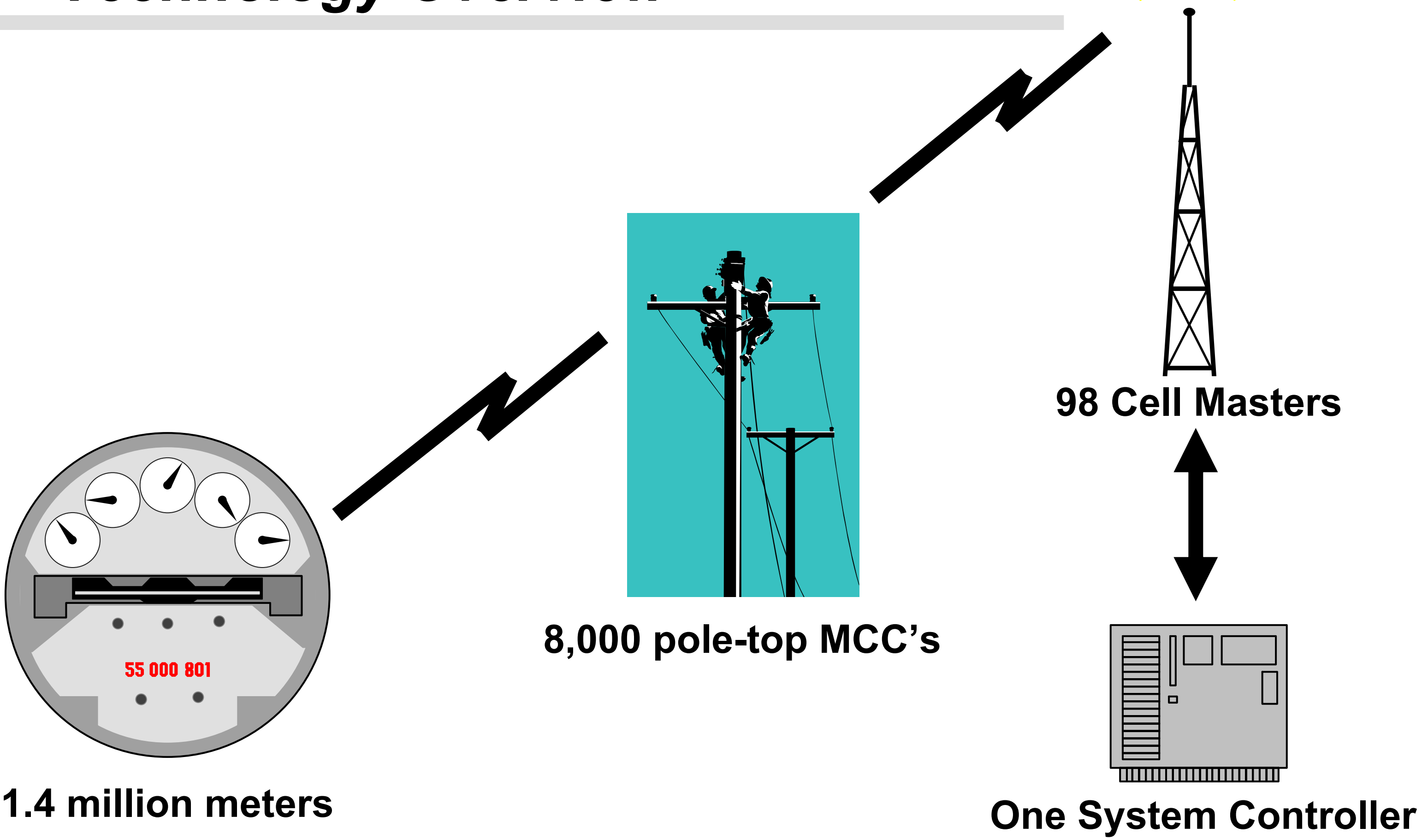
- AmerenUE's AMR system was deployed in 1996-2000 and covers both urban and rural areas
- The radio network covers about 98% of AmerenUE's meters, and about 2% is read with a mobile unit
- Cellnet, the nation's largest provider of fixed wireless networks, provides the service for Ameren



AmerenUE has ten years experience with its AMR system.

Ameren UE

AMR – Technology Overview



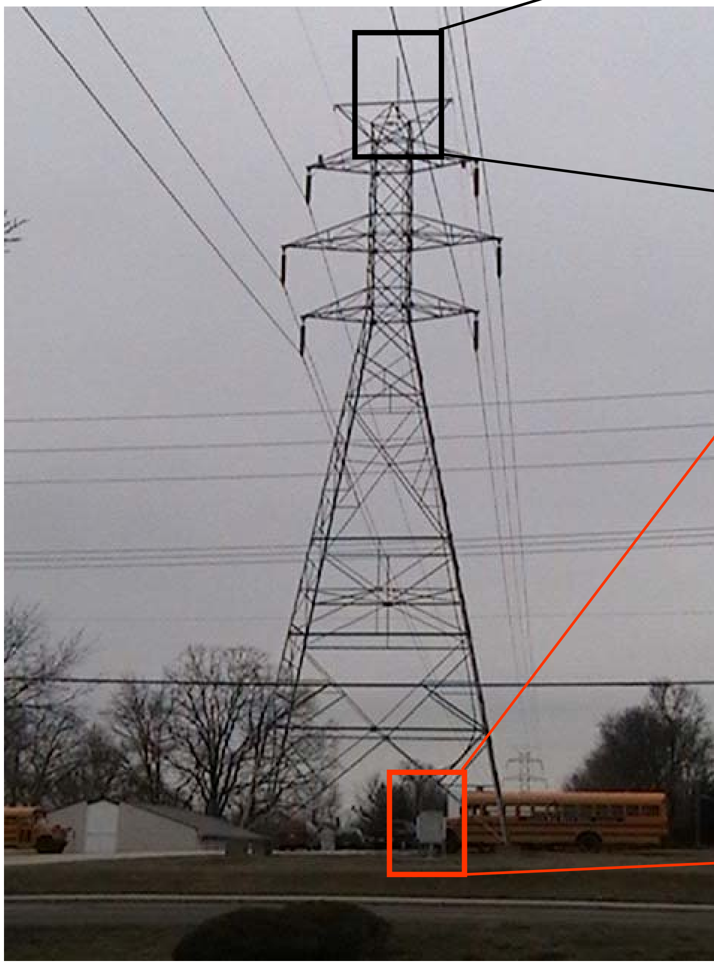
The electric meter transmits its reading every 5 minutes. Each transmission includes the readings from the past 45 minutes. This overlap provides some redundancy in the system.

AmerenUE

AMR Pole-Top MCC

MCC 41642

AMR Cell Master



TWIN OAKS
CELL MASTER

Agenda

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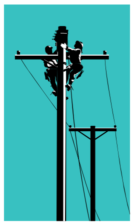
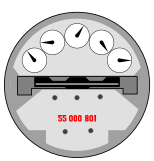
AMR – Time-based readings are determined two ways

- **At the pole-top**



  - The MCC receives packets of usage data from the meter.
  - The MCC is synchronized to standard time.
  - The MCC assigns the packets to the correct time bins (on-peak versus off-peak).

- **At the meter**



  - In a few cases AmerenUE has a “direct register read.”
  - The meter calculates the TOU usage and transmits the data.
  - This approach is more costly but offers additional benefits such as loss-of-phase to the meter.

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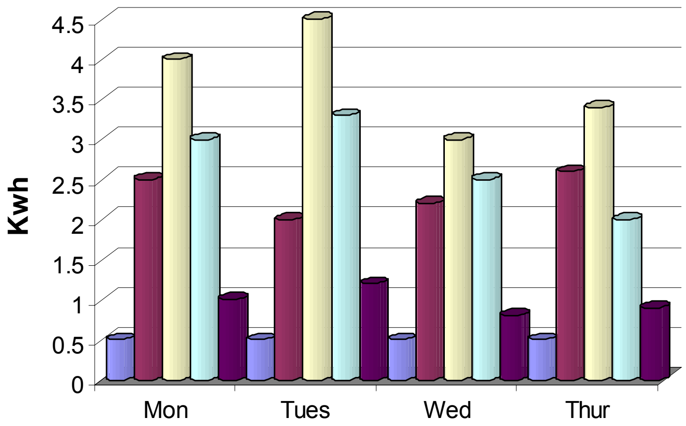
AMR – Operational benefits include

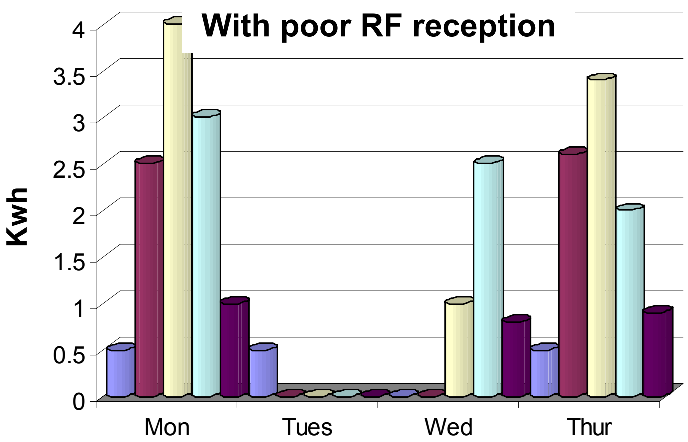
- Daily meter readings on more than 97% of the system
- Many fewer estimated bills compared to manual reads
- Less customer intrusion for meter reading
- Readings to move in or move out on any selected day
- Flexible billing dates for special need customers
- Daily usage history to help address high bill complaints
- Outage detection and restoration verification
- Diversion detection in some situations
- Detailed load data for engineering analysis
- Load survey data without installing expensive meters

AMR - Challenges

- Problem: Radio signals might be blocked or not heard intermittently for various reasons
- UE approach: Manage the interference issues by using only reliable automated data
- What some suggest doing: "Profile" the gaps based on assumptions. This approach cannot predict if a customer has changed their behavior.

An Example of Residential Usage with good RF reception





In a widespread TOU deployment, Ameren projects that 10-20% of the customers would be affected with these issues.

Ways to address radio interference issues

- Install antennas
- Move meter outside or reconfigure its position
- Install meter with stronger transmitter
- Install more pole-top units
- Upgrade receivers in pole-top units
- Determine the source of the interference and ask for it to be discontinued

All of these steps are costly and time-consuming, so these can feasibly be managed only in a moderate number of meters (such as what UE has today).

AmerenUE

Ways to bypass radio interference issues

Install a more expensive meter that calculates the demand or TOU information and read the meter manually.

Install a phone line or cellular phone for each meter.

These approaches are also not feasible in high numbers, since they are expensive, very labor intensive, and contrary to the benefits of an automated network

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AmerenUE Time-Based Rate Options

AmerenUE has had TOU energy rates in effect since 1994 for all rates classes. The residential rate has been in effect for more than 20 years.

Rate	Seasonal	Time of Use - Demand	Time of Use - Energy	Curtailable	Critical Peak Period	Real Time Pricing
1(M) - Residential	**Yes**	No	**Optional**	No	No	No
2(M) - Small General Service	**Yes**	No	**Optional**	No	No	No
3(M) - Large General Service	**Yes**	**Optional**	**Optional**	No	No	No
4(M) - Small Primary Service	**Yes**	**Yes**	**Optional**	No	No	No
11(M) - Large Primary Service	**Yes**	**Yes**	**Optional**	No	No	No
12(M) - Large Transmission Service	**Yes**	**Yes**	**Optional**	No	No	No
Rider L - Voluntary Curtailment	No	No	No	**Yes**	No	No
Rider M - Options Based Curtailment	No	No	No	**Yes**	No	No
Residential Time-of-Use Pilot	**Yes**	No	**Yes**	No	**Yes**	No

Excluding the Large Primary Service Class, the remaining rate classes have less than 1% of customers on TOU energy rate.

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Stipulation and Agreement AmerenUE Rate Case

"Collaborative committee of interested signatories will be established to design and evaluate an experimental residential TOU pilot project"

- Collaborative members
  - Office of Public Counsel
  - Missouri Public Service Commission
  - Department of Natural Resources
  - Two Industrial Intervener Groups
  - AmerenUE
- Goals
  - Satisfy stipulation agreement provision
  - Obtain information on benefits of residential TOU Rates in Missouri

AmerenUE

Pilot Summary

- Focus Groups to gather feedback on Residential TOU
- Start June 2004 lasting for 18 months
- 225 participants
  - Voluntary – participants recruited via telephone marketing
  - Customers can opt-out of pilot at any time
  - $25 incentive payment for signing up
  - $75 incentive payment after six-month period
- Three Treatment Groups (75 customers in each group)
  - Group 1: 3 part TOU w/ high differentials
  - Group 2: 3 part TOU w/ high differentials & CPP pricing
  - Group 3: Same as Group 2 w/ “smart” thermostats
- “Smart” thermostats to assist in changing behavior
- Customer Experience Focus Groups
- Pre/Post Survey

Pilot Project Design

- Three treatment groups AND Three Control Groups
- Geographical constraint – same area for thermostat control, installation, and employee training
- Target Population – high summer use customers (greatest potential for response) with high AMR communication reliability
- Sample design – stratified random sample of high summer use customers

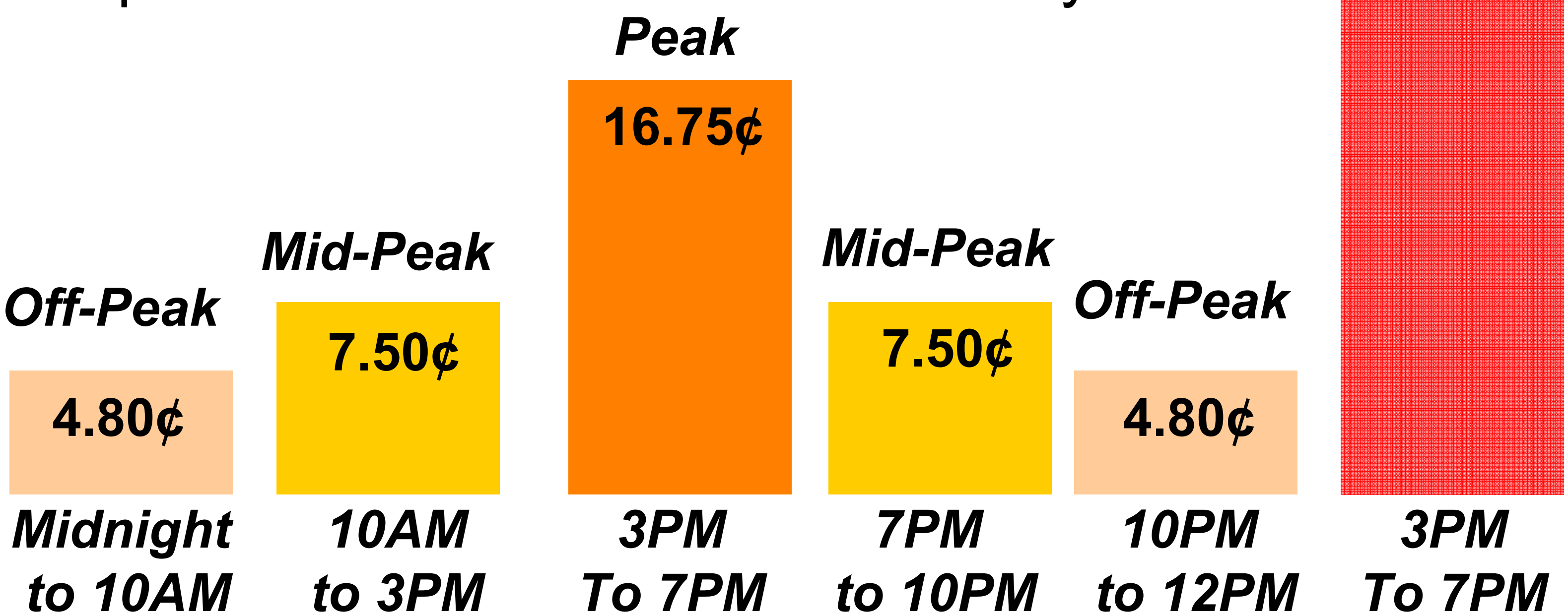
Load Research Residential Stratification

Strata	Description	Winter Use	Summer Use
1	Low Winter/Low Summer	0-1150 kWh	0-1500 kWh
2	High Winter/Low Summer	>1150 kWh	0-1500 kWh
3	Low Winter/High Summer	0-1150 kWh	>1500 kWh
4	High Winter/High Summer	>1150 kWh	>1500 kWh

AmerenUE

Pilot Summer Rate

- TOU Rate designed with high differentials
- Critical Peak Period Rate arbitrarily set at 30¢/KWH
- Pilot rates designed for revenue neutrality
- Customer Charge same as standard rate
- Separate Winter Rate for consistency



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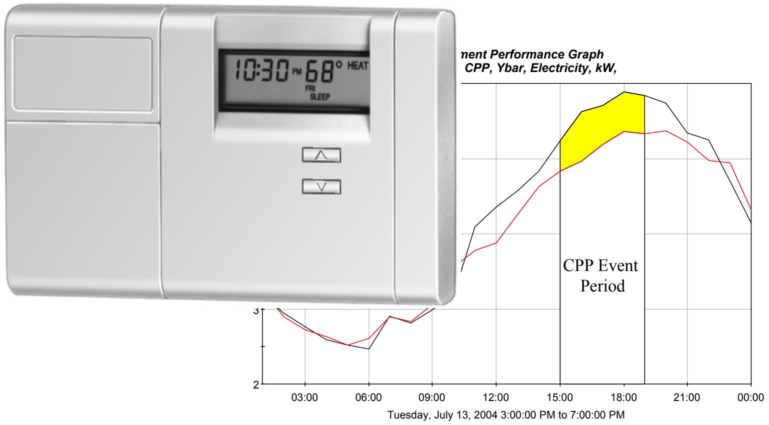
Pilot Technology

- 10% of the potential participants were eliminated in meter data pre-screening.
- An additional 10-15% a month had estimated bills during the pilot.
- CPP Notification via phone message and email.
- AmerenUE controlled thermostats during CPP.
- Almost all customers choose lowest control setting.
- Customer could opt-out of CPP.



CPP Options Thermostat Settings

Degree Per Hour	Maximum Change	Pre Cool (2 degrees)
1	4	No
2	4	No
2	6	No
2	8	No
2	6	Yes
2	8	Yes

AmerenUE

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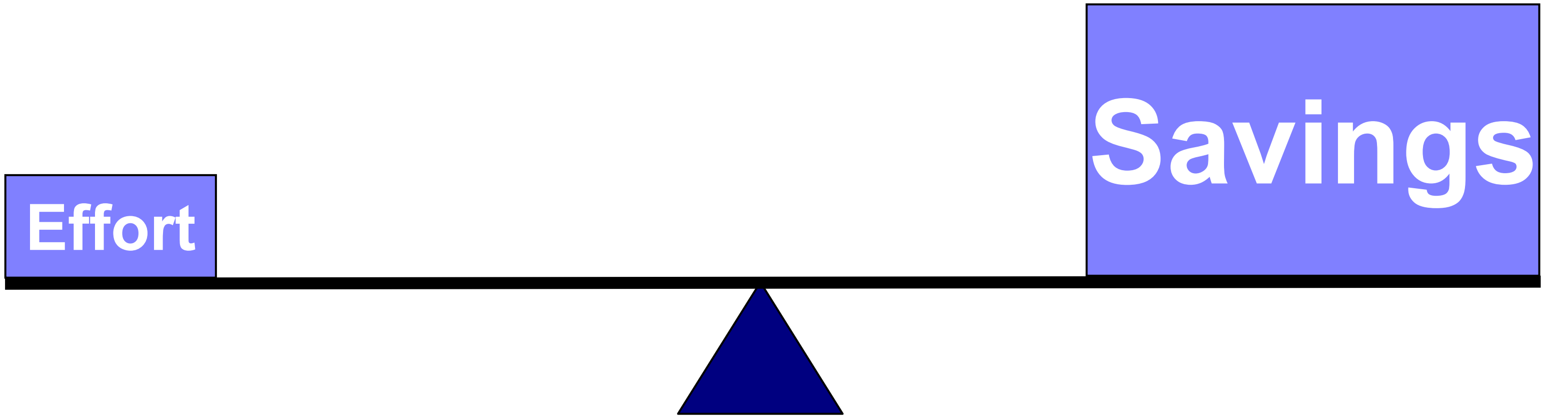
Choosing to Change/Savings

- Additional information about electrical usage gives customers insight on impact of certain devices on their electricity consumption.
- Once customers feel like they can control usage to their advantage, they may make a decision to choose to change.
- Customers expect minimal changes in their electricity consumption behavior to gain a great return in terms of savings.



Factors Working Against Change

- Inertia – things are fine the way they are.
- Ameren is an outside force.
  - Big brother usurping control
  - Rate structure is reward/punishment
- Need to impose discipline or self-discipline
  - Some people believe they do not have the self-discipline to make it work.
  - Parents (especially moms) believe that life is too short. It's not worth fighting over lights or the thermostat.
- Worry about an unexpected higher bill
- Home is my castle

Load Research Results

First Year – Load Research Results

Group	Energy Shift	Energy Conservation	CPP Reducation
1 TOU only	No	No	No
2 TOU w/ CPP	No	No	Yes
3 TOU w/ CPP w/ thermostat	Yes	Yes	Yes

- CPP
  - Is the observed load reduction during CPP hours real?
  - Do we keep the RTOU component or test just the CPP aspect of the rate?
- CPP with “smart” Thermostat
  - Is the decrease observed in all periods displayed by the CPP-“smart” Thermostat group real?
  - Can we isolate the impact of just the “smart” Thermostat?
  - Would customers shift load without an additional financial incentive?

AmerenUE

2005 EPAct Workshop

Governor Office Building, March 6, 2006

Net Metering & Interconnection

By Warren Wood, PE

Utility Operations Division Director, MoPSC Staff

Topics

1. **<u>Legislation</u>**

    Section 386.887 RSMo Supp 2002

2. **<u>Commission Rule</u>**

    Net Metering Rule 4 CSR 240 - 20.065

3. **<u>Interconnection Equipment</u>**

4. **<u>EPAct Net Metering & Interconnection Provisions</u>**

Net Metering Legislation

<u>Legislation:</u>

Following the 2001-2002 legislative session, the governor signed into law Section 386.887 (RSMo 2002 Supp) – the "Consumer Clean Energy Act". The provisions of this legislation (HB 1402) were hotly debated by numerous parties due to the limitations that this legislation contained that largely mimic the Public Utility Regulatory Policy Act (PURPA) regarding interconnection of alternative energy sources and appropriate compensation for excess generation.

Net Metering Legislation

Section 386.887 “Consumer Clean Energy Act”

- Permits interconnection of customer-generators with systems below 100 kW in size that are a hydrogen fuel cell or powered by sun, wind or biomass.
- Permits interconnection with all “retail electric suppliers” including IOUs, munis and coops.
- Requires measurement of power delivered to grid by customer generator and delivered to customer-generator by supplier separately.
- Applies retail rates (~0.08 $/kWh) to customer generator supplied power and avoided rates (~0.02 $/kWh) to customer generator delivered power.

Net Metering Legislation

"Consumer Clean Energy Act" – continued

- Limits participation to the lesser of 0.1% of previous year peak or 10,000 kW.
- Requires adherence to safety standards established by PSC, NESC, IEEE, UL and all reasonable standards and requirements established by retail electric supplier.
- Requires customer-generator to obtain liability insurance in amount set by PSC.
- Requires PSC development of a contract for transactions between the customer-generator and retail electric supplier.

I can forward a copy of the complete text of this statute if you are interested.

Missouri PSC Rules

<u>Rule 4 CSR 240-20.065:</u>

RSMO Section 386.887 required that the PSC develop rules for interconnection related to safety, contracts, certification and liability insurance. Technical conferences including representatives from a broad array of interest were active in these working meetings. The final outcome of these meetings was rule 4 CSR 240-20.065.

Missouri PSC Rules

4 CSR 240-20.065 “Net Metering”

- Duplicates much of RSMo 386.887 in PSC rules.
- Implements $100,000 liability insurance requirement.
- Creates contract for transactions between retail electric supplier and consumer generator.
- Contract Provisions Include:
  - Installation/Hardware Compliance
  - Operation/Disconnection/Termination Rights
  - Transfer of Ownership
  - Dispute Resolution

Missouri PSC Rules

"Net Metering" – continued

- Contract Provisions – continued
  - Inspection and Certification
  - Testing Recording & Reporting Requirements

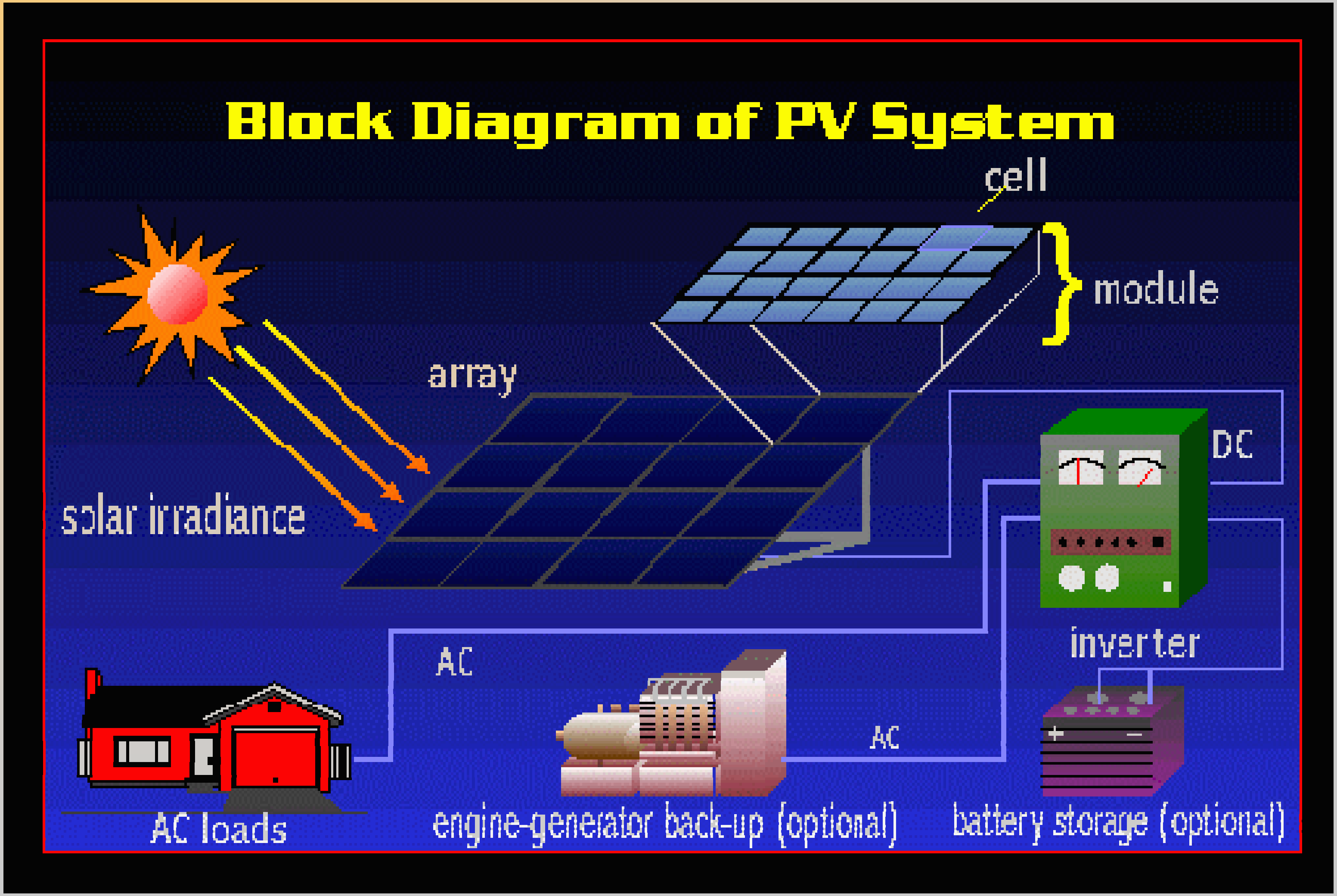
I have a copy of this rule, including the contract, if you are interested.

Interconnection Equipment

Interconnection Equipment:

- Energy source and conversion to electricity.
- Inverter for alternating current conversion, synchronization, isolation, and safety.
- Isolation switch for disconnect from power panel.
- Optional meter for measuring power generated.
- Optional batteries for energy storage and backup power.
- Optional alternative energy source for backup power.

Interconnection Equipment



Interconnection Equipment

Example Projects: Governor Office Building

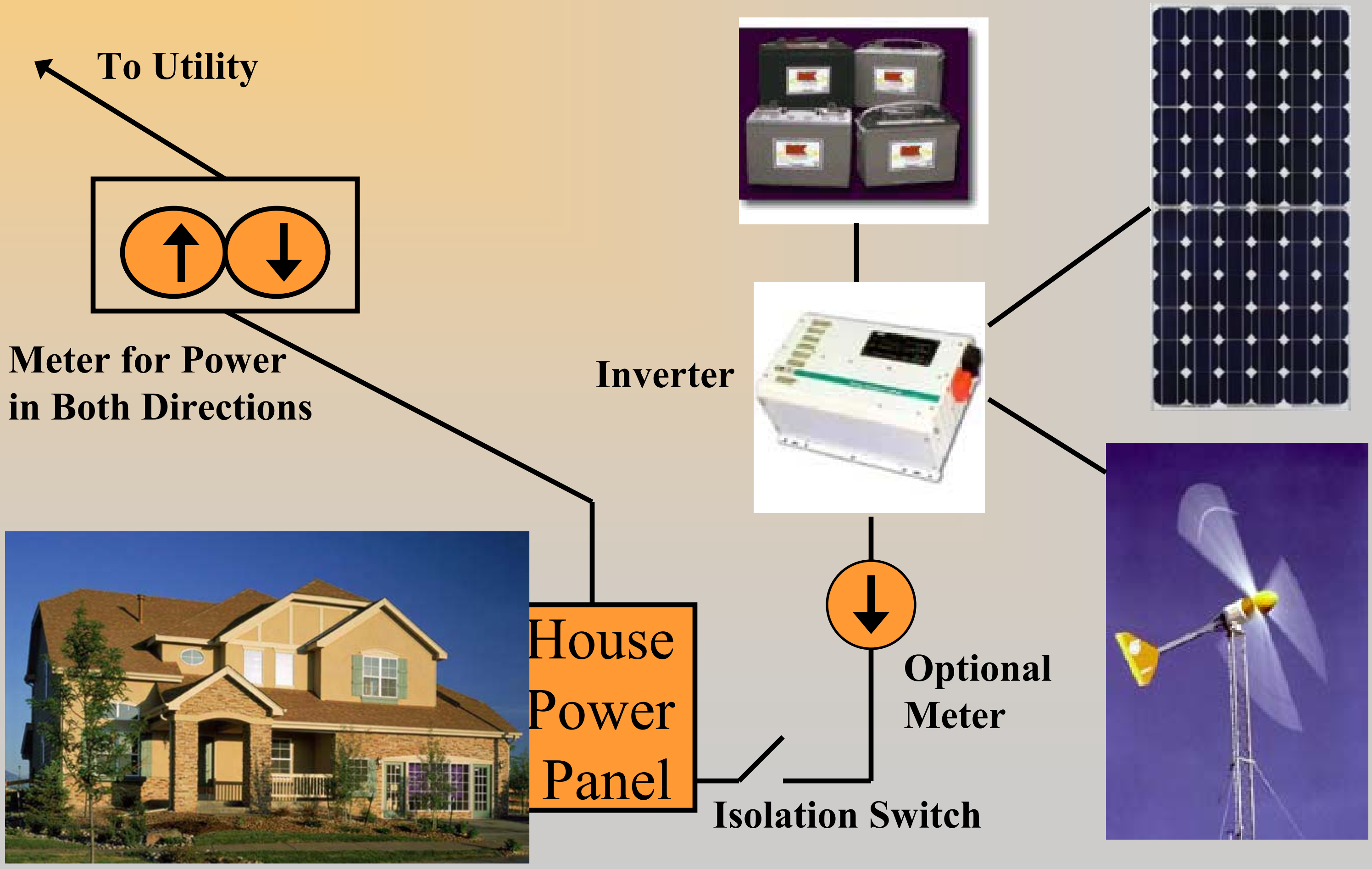
Interconnection Equipment

Inverter

Interconnection Equipment

Isolation Switch

Interconnection Equipment



EPAct Net Metering Provisions

Section 1251 – PURPA Section 111(d) Amendment

(11) NET METERING – Each electric utility shall make available upon request net metering service to any electric consumer that the electric utility serves. For purposes of this paragraph, the term ‘net metering service’ means service to an electric consumer under which electric energy generated by that electric consumer from an eligible on-site generating facility and delivered to the local distribution facilities may be used to offset electric energy provided by the electric utility to the electric consumer during the applicable billing period.

EPAct Net Metering Provisions

Time Limitations:

Not later than 2 years after the enactment of this paragraph, each State regulatory authority and each nonregulated electric utility shall commence the consideration referred to in section 111, or set a hearing date for such consideration.

Not later than 3 years after enactment of this paragraph, each State regulatory authority, and each nonregulated electric utility, shall complete the consideration, and shall make a determination regarding each standard.

EPAct Net Metering Provisions

Prior State Action (for section to not apply):

(1) The State has implemented for such utility the standard concerned (or a comparable standard);

(2) The State regulatory authority for such State or relevant nonregulated electric utility has conducted a proceeding to consider implementation of the standards concerned (or a comparable standard); or

(3) the State Legislature has voted on the implementation of such standard (or a comparable standard).

EPAct Interconnection Provisions

Section 1254 – PURPA Section 111(d) Amendment

(15) INTERCONNECTION – Each electric utility shall make available, upon request, interconnection service to any electric consumer that the electric utility serves. For purposes of this paragraph, the term 'interconnection service' means service to an electric consumer under which an on-site generating facility on the consumer's premises shall be connected to the local distribution facilities. Interconnection services shall be offered based upon the standards developed by the Institute of Electrical and Electronics Engineers: IEEE Standard 1547 for Interconnecting Distributed Resources with Electric Power Systems, as they may be amended from time to time.

EPAct Interconnection Provisions

Section 1254 – PURPA Section 111(d) Amendment

(15) INTERCONNECTION – continued

In addition, agreements and procedures shall be established whereby the services offered shall promote current best practices of interconnection for distributed generation, including but not limited to practices stipulated in model codes adopted by associations of state regulatory agencies. All such agreements and procedures shall be just and reasonable, and not unduly discriminatory or preferential.

EPAct Interconnection Provisions

Time Limitations:

Not later than 1 year after the enactment of this paragraph, each State regulatory authority and each nonregulated electric utility shall commence the consideration referred to in section 111, or set a hearing date for such consideration.

Not later than 2 years after enactment of this paragraph, each State regulatory authority, and each nonregulated electric utility, shall complete the consideration, and shall make a determination regarding each standard.

EPAct Interconnection Provisions

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EPAct Interconnection Provisions

Note difference in IEEE Standards:

EPAct Refers to IEEE Standard 1547 for Interconnecting Distributed Resources with Electric Power Systems

Current PSC Rule Refers to IEEE Standard 929-2000 and UL 1741.

Contact Information:

Warren Wood

MO Public Service Commission

PO Box 360

Jefferson City, MO 65102

Phone: (573) 751-2978

Cell: (573) 864-1213

Fax: (573) 751-1847

E-mail: Warren.Wood@psc.mo.gov

Outline of Net Metering Presentation to MoPSC Technical Conference on 3/6/06
(Presented by Bill Eichman, Mgr of Industrial/Commercial Energy Services at Empire District)

- Brief history of Empire's Pre-PURPA interconnection standards and examples.
- Empire's first interconnection with PURPA Qualified residential wind generator near Seneca (late 70's/early 80's). (Unit was rated at a "few hundred" watts and was retired about 6 years later).
- Empire's "Formal" development of standards for "small" PURPA Qualified units in 1980-81.
- Empire's interconnection with first unit of first commercial "Wind Park" in 1983 at Radar Hill, near Oronogo. (This 25 KW unit was damaged in accident within 2 – 3 months after interconnection. Wind Park plans were cancelled by developer).
- Empire's interconnection with industrial customer's Sawdust-Fueled Generation in 1985 in Neosho. (These two 250 KW units were retired in early 1990's).
- Empire's interconnection with 900 watt Photovoltaic system at doctor's office in Sarcoxie in 1990. (Later expanded to 1800 watts before being retired in approximately 1995).
- Empire's interconnection with residential 10 KW Wind Generator near Carthage in 2002. (Still in service).
- Empire's interconnection with residential 4.8 KW Photovoltaic system near Carthage in 2003. (Still in Service).
- Empire's interconnection with 525 KW Landfill-Gas Fueled Boiler/Turbine/Generator system near Neosho in December, 2005.
- Other potential interconnections on the horizon.

Fuel Diversity & Generation Efficiency

PURPA Sec. 111(d)(12) & Sec. 111(d)(13)

Lena Mantle
Manager Energy Department
Missouri Public Service Commission

March 6, 2006

PURPA Sec. 111(d)(12) & Sec. 111(d)(13)

(12) FUEL SOURCES - Each electric utility shall develop a plan to minimize dependence on 1 fuel source and to ensure that the electric energy it sells to consumers is generated using a diverse range of fuels and technologies, including renewable technologies.

(13) FOSSIL FUEL GENERATION EFFICIENCY- Each electric utility shall develop and implement a 10-year plan to increase the efficiency of its fossil fuel generation.

4 CSR 240-22.040 Supply-Side Resource Analysis

(1) The analysis of supply-side resources shall begin with the identification of a variety of potential supply-side resource options which the utility can reasonably expect to develop and implement solely through its own resources or for which it will be a major participant.

4 CSR 240-22.040 Supply-Side Resource Analysis

- new plants using existing generation technologies;
- new plants using new generation technologies;
- life extension and refurbishment at existing generating plants;
- enhancement of the emission controls at existing or new generating plants;
- purchased power from utility sources, cogenerators or independent power producers;
- efficiency improvements which reduce the utility's own use of energy; and
- upgrading of the transmission and distribution systems to reduce power and energy losses.

4 CSR 240-22.040 Supply-Side Resource Analysis

(4) The utility shall identify and analyze opportunities for life extension and refurbishment of existing generation plants, taking into account their current condition to the extent that it is significant in the planning process.

Questions

- Are Mo electric utilities too dependent upon one fuel type?
- Are Mo electric utilities not taking advantage of efficiency improvement opportunities in their current resources?
- Does the Commission/Legislature need to take action?
- If action needs to be taken, what action needs to be taken?

Workshop
2005 Energy Policy Act's New PURPA Sec. 111(d) Standards for Electric Utilities
Monday, March 6, 2006
Governor Office Building Room 470

The Empire District Electric Company
Relevant Prior State Actions and Compliance

PURPA Sec. 111(d)(12) FUEL SOURCES- Each electric utility shall develop a plan to minimize dependence on 1 fuel source and to ensure that the electric energy it sells to consumers is generated using a diverse range of fuels and technologies, including renewable technologies.

1. The existing Missouri IRP rulemaking requires each utility to analyze different fuel sources, different technology types, renewable resources and demand side measures in order to develop a robust resource plan to serve the electrical needs of our customers under a variety of future scenarios. It is Empire's belief that a properly developed IRP plan will contain a diverse mix of resources and technologies.
2. There are currently bills in the Missouri House of Representatives and in the Missouri Senate that include renewable energy standards. The bills range from mandatory requirements to voluntary targets. We will need to adapt to any requirement from the legislature.
3. We need to be aware that non-economic drivers may not allow for the least cost plan to be developed. 4 CSR 240-22.010 (2) (B) states "Use minimization of the present worth of long-run utility costs as the primary selection criterion in choosing the preferred resource plan.."

PURPA Sec. 111(d)(13) FOSSIL FUEL GENERATION EFFICIENCY- Each electric utility shall develop and implement a 10-year plan to increase the efficiency of its fossil fuel generation.

1. It is difficult to change the thermal efficiency on existing resources within the confines of initial design. If we make changes beyond routine maintenance and repair we risk triggering New Source Review.
2. Each utility will be challenged in the short run as air pollution control equipment is added to existing coal fired boilers to maintain compliance with air quality regulations. The air pollution control equipment will take power to run and will have a detrimental effect on efficiency.
3. Missouri's NSR regulations have not been adopted by EPA into Missouri's EPA approved State Implementation Plan. Missouri's NSR regulations contain provisions for improvements in efficiency.

3. WORKSHOP ATTENDANCE LIST

EPACT

Denny Frey

Workshop Agenda for
2005 Energy Policy Act's
New PURPA Sec. 111(d) Standards for Electric Utilities
Monday, March 6, 2006 – 10:00am to 5:00pm
Governor Office Building Room 470

Name	Organization	Phone	Email
1. Bob Quinn	ratepayer	573-635-1370	bquinn74@earthlink.net
2. Greg Meyer	MoPSC	314-340-4680	greg.meyer@psc.mo.gov
3. Matt Tracy	Aquila	816-737-7769	matt.Tracy@aquila.com
4. Mike Whitmore	AmerenUE	314-554-2380	mwhitmore@ameren.com
5. John Luth	Ameren UE	314-992-6884	jluth@ameren.com
6. Craig Johnson	Atty	632-1900	craig@csjohnsonlaw.com
7. Bob Mill	Ameren UE	314-554-3734	bmill@ameren.com
8. Mike Proctor	MoPSC	314-340-4690	mike.proctor@psc.mo.gov
9. Jay Hasheider	Columbia Water & Light	573-874-7685	rjh@gocolumbiamo.com
10. Brad Beecher	Empire	417 625 4260	bbeecher@empiredistrict.com
11. Lois Liechti	KCPL	816 556 2612	lois.liechti@kcpl.com
12. Marsha Troy	KCPL	816-556-2327	marsha.troy@kcpl.com
13. Andrew Sporleder	Atty	634-3422	ASporleder@[illegible].com
14. Larry Plevs	Ameren	681-7202	lplevs@ameren.com
15. Stu Conrad	FCP	816-753-1122	stucon@fcplaw.com
16. Jeff Davis	PSC	751-3233	Jeff.Davis@psc.mo.gov
17. Ryan Kind	OPC	751-5563	ryan.kind@ded.mo.gov
18. Bill Eichman	EDE	417-625-5116	beichman@empiredistrict.com
19. Kelly Walters	EDE	417-625-6188	kwalters@empiredistrict.com
20. Todd Tarter	EDE	417-625-6577	ttarter@empiredistrict.com

Workshop Agenda for
2005 Energy Policy Act's
New PURPA Sec. 111(d) Standards for Electric Utilities
Monday, March 6, 2006 – 10:00am to 5:00pm
Governor Office Building Room 470

21. Denny Frey	Commission Staff	573-751-8700	denny.frey@psc.mo.gov
22. Becky Kilpatrick	Exec	526-4857	
23. Wendy Tatro	Ameren	314-554-3484	
24. Angie Robinson	Exec	1-7504	
25. Ken McClure	Governor's Office	1-5261	
26. Bob Keller	KCMO		
27. Gerald Fellers	MAMU	5734453279	dfeller@MPUA.org
28. Anita Randolph	MoDNR	573-751-2254	anita.randolph@dnr.mo.gov
29. Brenda Wilbers	MoDNR	573-751-8509	brenda.wilbers@dnr.mo.gov
30. Carmen Morrissey	MoPSC	573-751-7531	c.morrissey@psc.mo.gov
31. Dan Beck	MoPSC	573-751-7522	dan.beck@psc.mo.gov
32. George Phillips	KCP&L	618-556-2648	george.phillips@kcpl.com
33.			
34.			
35.			

4. Advance Reference Materials

22-638

2005
109TH CONGRESS *1ST SESSION*
Report
HOUSE OF REPRESENTATIVES
Report

109-190

ENERGY POLICY ACT OF 2005

CONFERENCE REPORT

[To accompany H.R. 6]

[Graphic image not available]

JULY 27, 2005- Ordered to be printed

ENERGY POLICY ACT OF 2005

22-638

2005
109TH CONGRESS *1ST SESSION*
Report
HOUSE OF REPRESENTATIVES
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109-190

ENERGY POLICY ACT OF 2005

CONFERENCE REPORT

[To accompany H.R. 6]

[Graphic image not available]

JULY 27, 2005- Ordered to be printed

22-638

109TH CONGRESS

Report

reasonable and not unduly discriminatory or preferential.'.

SEC. 1242. FUNDING NEW INTERCONNECTION AND TRANSMISSION UPGRADES.

The Commission may approve a participant funding plan that allocates costs related to transmission upgrades or new generator interconnection, without regard to whether an applicant is a member of a Commission-approved Transmission Organization, if the plan results in rates that--

(1) are just and reasonable;

(2) are not unduly discriminatory or preferential; and

(3) are otherwise consistent with sections 205 and 206 of the Federal Power Act (16 U.S.C. 824d, 824e).

Subtitle E--Amendments to PURPA

SEC. 1251. NET METERING AND ADDITIONAL STANDARDS.

(a) Adoption of Standards- Section 111(d) of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2621(d)) is amended by adding at the end the following:

`(11) NET METERING- Each electric utility shall make available upon request net metering service to any electric consumer that the electric utility serves. For purposes of this paragraph, the term `net metering service' means service to an electric consumer under which electric energy generated by that electric consumer from an eligible on-site generating facility and delivered to the local distribution facilities may be used to offset electric energy provided by the electric utility to the electric consumer during the applicable billing period.

`(12) FUEL SOURCES- Each electric utility shall develop a plan to minimize dependence on 1 fuel source and to ensure that the electric energy it sells to consumers is generated using a diverse range of fuels and technologies, including renewable technologies.

`(13) FOSSIL FUEL GENERATION EFFICIENCY- Each electric utility shall develop and implement a 10-year plan to increase the efficiency of its fossil fuel generation.'.

(b) Compliance-

(1) TIME LIMITATIONS- Section 112(b) of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2622(b)) is amended by adding at the end the following:

`(3)(A) Not later than 2 years after the enactment of this paragraph, each State

regulatory authority (with respect to each electric utility for which it has ratemaking authority) and each nonregulated electric utility shall commence the consideration referred to in section 111, or set a hearing date for such consideration, with respect to each standard established by paragraphs (11) through (13) of section 111(d).

`(B) Not later than 3 years after the date of the enactment of this paragraph, each State regulatory authority (with respect to each electric utility for which it has ratemaking authority), and each nonregulated electric utility, shall complete the consideration, and shall make the determination, referred to in section 111 with respect to each standard established by paragraphs (11) through (13) of section 111(d).'.

(2) FAILURE TO COMPLY- Section 112(c) of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2622(c)) is amended by adding at the end the following: `In the case of each standard established by paragraphs (11) through (13) of section 111(d), the reference contained in this subsection to the date of enactment of this Act shall be deemed to be a reference to the date of enactment of such paragraphs (11) through (13).'.

(3) PRIOR STATE ACTIONS-

(A) IN GENERAL- Section 112 of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2622) is amended by adding at the end the following:

`(d) Prior State Actions- Subsections (b) and (c) of this section shall not apply to the standards established by paragraphs (11) through (13) of section 111(d) in the case of any electric utility in a State if, before the enactment of this subsection--

`(1) the State has implemented for such utility the standard concerned (or a comparable standard);

`(2) the State regulatory authority for such State or relevant nonregulated electric utility has conducted a proceeding to consider implementation of the standard concerned (or a comparable standard) for such utility; or

`(3) the State legislature has voted on the implementation of such standard (or a comparable standard) for such utility.'.

(B) CROSS REFERENCE- Section 124 of such Act (16 U.S.C. 2634) is amended by adding the following at the end thereof: `In the case of each standard established by paragraphs (11) through (13) of section 111(d), the reference contained in this subsection to the date of enactment of this Act shall be deemed to be a reference to the date of enactment of such paragraphs (11) through (13).'.

SEC. 1252. SMART METERING.

(a) In General- Section 111(d) of the Public Utility Regulatory Policies Act of 1978 (16

U.S.C. 2621(d)) is amended by adding at the end the following:

`(14) TIME-BASED METERING AND COMMUNICATIONS- (A) Not later than 18 months after the date of enactment of this paragraph, each electric utility shall offer each of its customer classes, and provide individual customers upon customer request, a time-based rate schedule under which the rate charged by the electric utility varies during different time periods and reflects the variance, if any, in the utility's costs of generating and purchasing electricity at the wholesale level. The time-based rate schedule shall enable the electric consumer to manage energy use and cost through advanced metering and communications technology.

`(B) The types of time-based rate schedules that may be offered under the schedule referred to in subparagraph (A) include, among others--

`(i) time-of-use pricing whereby electricity prices are set for a specific time period on an advance or forward basis, typically not changing more often than twice a year, based on the utility's cost of generating and/or purchasing such electricity at the wholesale level for the benefit of the consumer. Prices paid for energy consumed during these periods shall be pre-established and known to consumers in advance of such consumption, allowing them to vary their demand and usage in response to such prices and manage their energy costs by shifting usage to a lower cost period or reducing their consumption overall;

`(ii) critical peak pricing whereby time-of-use prices are in effect except for certain peak days, when prices may reflect the costs of generating and/or purchasing electricity at the wholesale level and when consumers may receive additional discounts for reducing peak period energy consumption;

`(iii) real-time pricing whereby electricity prices are set for a specific time period on an advanced or forward basis, reflecting the utility's cost of generating and/or purchasing electricity at the wholesale level, and may change as often as hourly; and

`(iv) credits for consumers with large loads who enter into pre-established peak load reduction agreements that reduce a utility's planned capacity obligations.

`(C) Each electric utility subject to subparagraph (A) shall provide each customer requesting a time-based rate with a time-based meter capable of enabling the utility and customer to offer and receive such rate, respectively.

`(D) For purposes of implementing this paragraph, any reference contained in this section to the date of enactment of the Public Utility Regulatory Policies Act of 1978 shall be deemed to be a reference to the date of enactment of this paragraph.

`(E) In a State that permits third-party marketers to sell electric energy to retail electric consumers, such consumers shall be entitled to receive the same time-based metering and communications device and service as a retail electric consumer of the electric utility.

`(F) Notwithstanding subsections (b) and (c) of section 112, each State regulatory authority shall, not later than 18 months after the date of enactment of this paragraph conduct an investigation in accordance with section 115(i) and issue a decision whether it is appropriate to implement the standards set out in subparagraphs (A) and (C).'.

(b) State Investigation of Demand Response and Time-Based Metering- Section 115 of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2625) is amended as follows:

(1) By inserting in subsection (b) after the phrase `the standard for time-of-day rates established by section 111(d)(3)' the following: `and the standard for time-based metering and communications established by section 111(d)(14)'.

(2) By inserting in subsection (b) after the phrase `are likely to exceed the metering' the following: `and communications'.

(3) By adding the at the end the following:

`(i) Time-Based Metering and Communications- In making a determination with respect to the standard established by section 111(d)(14), the investigation requirement of section 111(d)(14)(F) shall be as follows: Each State regulatory authority shall conduct an investigation and issue a decision whether or not it is appropriate for electric utilities to provide and install time-based meters and communications devices for each of their customers which enable such customers to participate in time-based pricing rate schedules and other demand response programs.'.

(c) Federal Assistance on Demand Response- Section 132(a) of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2642(a)) is amended by striking `and' at the end of paragraph (3), striking the period at the end of paragraph (4) and inserting `; and', and by adding the following at the end thereof:

`(5) technologies, techniques, and rate-making methods related to advanced metering and communications and the use of these technologies, techniques and methods in demand response programs.'.

(d) Federal Guidance- Section 132 of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2642) is amended by adding the following at the end thereof:

`(d) Demand Response- The Secretary shall be responsible for--

`(1) educating consumers on the availability, advantages, and benefits of advanced metering and communications technologies, including the funding of demonstration

or pilot projects;

`(2) working with States, utilities, other energy providers and advanced metering and communications experts to identify and address barriers to the adoption of demand response programs; and

`(3) not later than 180 days after the date of enactment of the Energy Policy Act of 2005, providing Congress with a report that identifies and quantifies the national benefits of demand response and makes a recommendation on achieving specific levels of such benefits by January 1, 2007.'.

(e) Demand Response and Regional Coordination-

(1) IN GENERAL- It is the policy of the United States to encourage States to coordinate, on a regional basis, State energy policies to provide reliable and affordable demand response services to the public.

(2) TECHNICAL ASSISTANCE- The Secretary shall provide technical assistance to States and regional organizations formed by 2 or more States to assist them in--

(A) identifying the areas with the greatest demand response potential;

(B) identifying and resolving problems in transmission and distribution networks, including through the use of demand response;

(C) developing plans and programs to use demand response to respond to peak demand or emergency needs; and

(D) identifying specific measures consumers can take to participate in these demand response programs.

(3) REPORT- Not later than 1 year after the date of enactment of the Energy Policy Act of 2005, the Commission shall prepare and publish an annual report, by appropriate region, that assesses demand response resources, including those available from all consumer classes, and which identifies and reviews--

(A) saturation and penetration rate of advanced meters and communications technologies, devices and systems;

(B) existing demand response programs and time-based rate programs;

(C) the annual resource contribution of demand resources;

(D) the potential for demand response as a quantifiable, reliable resource for regional planning purposes;

(E) steps taken to ensure that, in regional transmission planning and

operations, demand resources are provided equitable treatment as a quantifiable, reliable resource relative to the resource obligations of any load-serving entity, transmission provider, or transmitting party; and

(F) regulatory barriers to improved customer participation in demand response, peak reduction and critical period pricing programs.

(f) Federal Encouragement of Demand Response Devices- It is the policy of the United States that time-based pricing and other forms of demand response, whereby electricity customers are provided with electricity price signals and the ability to benefit by responding to them, shall be encouraged, the deployment of such technology and devices that enable electricity customers to participate in such pricing and demand response systems shall be facilitated, and unnecessary barriers to demand response participation in energy, capacity and ancillary service markets shall be eliminated. It is further the policy of the United States that the benefits of such demand response that accrue to those not deploying such technology and devices, but who are part of the same regional electricity entity, shall be recognized.

(g) Time Limitations- Section 112(b) of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2622(b)) is amended by adding at the end the following:

`(4)(A) Not later than 1 year after the enactment of this paragraph, each State regulatory authority (with respect to each electric utility for which it has ratemaking authority) and each nonregulated electric utility shall commence the consideration referred to in section 111, or set a hearing date for such consideration, with respect to the standard established by paragraph (14) of section 111(d).

`(B) Not later than 2 years after the date of the enactment of this paragraph, each State regulatory authority (with respect to each electric utility for which it has ratemaking authority), and each nonregulated electric utility, shall complete the consideration, and shall make the determination, referred to in section 111 with respect to the standard established by paragraph (14) of section 111(d).'.

(h) Failure to Comply- Section 112(c) of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2622(c)) is amended by adding at the end the following:

`In the case of the standard established by paragraph (14) of section 111(d), the reference contained in this subsection to the date of enactment of this Act shall be deemed to be a reference to the date of enactment of such paragraph (14).'.

(i) Prior State Actions Regarding Smart Metering Standards-

(1) IN GENERAL- Section 112 of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2622) is amended by adding at the end the following:

`(e) Prior State Actions- Subsections (b) and (c) of this section shall not apply to the standard established by paragraph (14) of section 111(d) in the case of any electric

utility in a State if, before the enactment of this subsection--

`(1) the State has implemented for such utility the standard concerned (or a comparable standard);

`(2) the State regulatory authority for such State or relevant nonregulated electric utility has conducted a proceeding to consider implementation of the standard concerned (or a comparable standard) for such utility within the previous 3 years; or

`(3) the State legislature has voted on the implementation of such standard (or a comparable standard) for such utility within the previous 3 years.'.

(2) CROSS REFERENCE- Section 124 of such Act (16 U.S.C. 2634) is amended by adding the following at the end thereof: `In the case of the standard established by paragraph (14) of section 111(d), the reference contained in this subsection to the date of enactment of this Act shall be deemed to be a reference to the date of enactment of such paragraph (14).'.

SEC. 1253. COGENERATION AND SMALL POWER PRODUCTION PURCHASE AND SALE REQUIREMENTS.

(a) Termination of Mandatory Purchase and Sale Requirements- Section 210 of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 824a-3) is amended by adding at the end the following:

`(m) Termination of Mandatory Purchase and Sale Requirements-

`(1) OBLIGATION TO PURCHASE- After the date of enactment of this subsection, no electric utility shall be required to enter into a new contract or obligation to purchase electric energy from a qualifying cogeneration facility or a qualifying small power production facility under this section if the Commission finds that the qualifying cogeneration facility or qualifying small power production facility has nondiscriminatory access to--

`(A)(i) independently administered, auction-based day ahead and real time wholesale markets for the sale of electric energy; and (ii) wholesale markets for long-term sales of capacity and electric energy; or

`(B)(i) transmission and interconnection services that are provided by a Commission-approved regional transmission entity and administered pursuant to an open access transmission tariff that affords nondiscriminatory treatment to all customers; and (ii) competitive wholesale markets that provide a meaningful opportunity to sell capacity, including long-term and short-term sales, and electric energy, including long-term, short-term and real-time sales, to buyers other than the utility to which the qualifying facility is interconnected. In determining whether a meaningful opportunity to sell

intended fundamentally for sale to an electric utility, taking into account technological, efficiency, economic, and variable thermal energy requirements, as well as State laws applicable to sales of electric energy from a qualifying facility to its host facility; and

`(iii) continuing progress in the development of efficient electric energy generating technology.

`(B) The rule issued pursuant to paragraph (1)(A) of this subsection shall be applicable only to facilities that seek to sell electric energy pursuant to section 210 of this Act. For all other purposes, except as specifically provided in subsection (m)(2)(A), qualifying facility status shall be determined in accordance with the rules and regulations of this Act.

`(2) Notwithstanding rule revisions under paragraph (1), the Commission's criteria for qualifying cogeneration facilities in effect prior to the date on which the Commission issues the final rule required by paragraph (1) shall continue to apply to any cogeneration facility that--

`(A) was a qualifying cogeneration facility on the date of enactment of subsection (m), or

`(B) had filed with the Commission a notice of self-certification, self-recertification or an application for Commission certification under 18 C.F.R. 292.207 prior to the date on which the Commission issues the final rule required by paragraph (1).'.

(b) Elimination of Ownership Limitations-

(1) QUALIFYING SMALL POWER PRODUCTION FACILITY- Section 3(17)(C) of the Federal Power Act (16 U.S.C. 796(17)(C)) is amended to read as follows:

`(C) `qualifying small power production facility' means a small power production facility that the Commission determines, by rule, meets such requirements (including requirements respecting fuel use, fuel efficiency, and reliability) as the Commission may, by rule, prescribe;'.

(2) QUALIFYING COGENERATION FACILITY- Section 3(18)(B) of the Federal Power Act (16 U.S.C. 796(18)(B)) is amended to read as follows:

`(B) `qualifying cogeneration facility' means a cogeneration facility that the Commission determines, by rule, meets such requirements (including requirements respecting minimum size, fuel use, and fuel efficiency) as the Commission may, by rule, prescribe;'.

SEC. 1254. INTERCONNECTION.

(a) Adoption of Standards- Section 111(d) of the Public Utility Regulatory Policies Act of

1978 (16 U.S.C. 2621 (d)) is amended by adding at the end the following:

`(15) INTERCONNECTION- Each electric utility shall make available, upon request, interconnection service to any electric consumer that the electric utility serves. For purposes of this paragraph, the term `interconnection service' means service to an electric consumer under which an on-site generating facility on the consumer's premises shall be connected to the local distribution facilities. Interconnection services shall be offered based upon the standards developed by the Institute of Electrical and Electronics Engineers: IEEE Standard 1547 for Interconnecting Distributed Resources with Electric Power Systems, as they may be amended from time to time. In addition, agreements and procedures shall be established whereby the services are offered shall promote current best practices of interconnection for distributed generation, including but not limited to practices stipulated in model codes adopted by associations of state regulatory agencies. All such agreements and procedures shall be just and reasonable, and not unduly discriminatory or preferential.'.

(b) Compliance-

(1) TIME LIMITATIONS- Section 112(b) of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2622(b)) is amended by adding at the end the following:

`(5)(A) Not later than one year after the enactment of this paragraph, each State regulatory authority (with respect to each electric utility for which it has ratemaking authority) and each nonregulated utility shall commence the consideration referred to in section 111, or set a hearing date for consideration, with respect to the standard established by paragraph (15) of section 111(d).

`(B) Not later than two years after the date of the enactment of the this paragraph, each State regulatory authority (with respect to each electric utility for which it has ratemaking authority), and each nonregulated electric utility, shall complete the consideration, and shall make the determination, referred to in section 111 with respect to each standard established by paragraph (15) of section 111(d).'.

(2) FAILURE TO COMPLY- Section 112(d) of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2622 (c)) is amended by adding at the end the following: `In the case of the standard established by paragraph (15), the reference contained in this subsection to the date of enactment of this Act shall be deemed to be a reference to the date of enactment of paragraph (15).'.

(3) PRIOR STATE ACTIONS-

(A) IN GENERAL- Section 112 of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2622) is amended by adding at the end the following:

`(f) Prior State Actions- Subsections (b) and (c) of this section shall not apply to the

standard established by paragraph (15) of section 111(d) in the case of any electric utility in a State if, before the enactment of this subsection--

`(1) the State has implemented for such utility the standard concerned (or a comparable standard);

`(2) the State regulatory authority for such State or relevant nonregulated electric utility has conducted a proceeding to consider implementation of the standard concerned (or a comparable standard) for such utility; or

`(3) the State legislature has voted on the implementation of such standard (or a comparable standard) for such utility.'.

(B) CROSS REFERENCE- Section 124 of such Act (16 U.S.C. 2634) is amended by adding the following at the end thereof: `In the case of each standard established by paragraph (15) of section 111(d), the reference contained in this subsection to the date of enactment of the Act shall be deemed to be a reference to the date of enactment of paragraph (15).'.

Subtitle F--Repeal of PUHCA

SEC. 1261. SHORT TITLE.

This subtitle may be cited as the `Public Utility Holding Company Act of 2005'.

SEC. 1262. DEFINITIONS.

For purposes of this subtitle:

(1) AFFILIATE- The term `affiliate' of a company means any company, 5 percent or more of the outstanding voting securities of which are owned, controlled, or held with power to vote, directly or indirectly, by such company.

(2) ASSOCIATE COMPANY- The term `associate company' of a company means any company in the same holding company system with such company.

(3) COMMISSION- The term `Commission' means the Federal Energy Regulatory Commission.

(4) COMPANY- The term `company' means a corporation, partnership, association, joint stock company, business trust, or any organized group of persons, whether incorporated or not, or a receiver, trustee, or other liquidating agent of any of the foregoing.

(5) ELECTRIC UTILITY COMPANY- The term `electric utility company' means any company that owns or operates facilities used for the generation, transmission, or distribution of electric energy for sale.

Public Utility Regulatory Policies Act of 1978

P.L. 95-617, November 9, 1978, as amended by P.L. 96-294, June 30, 1980, P.L. 98-620, November 8, 1984, P.L. 99-495, October 16, 1986, P.L. 101-575, November 15, 1990, and P.L. 102-486, October 24, 1992

Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled,

Sec. 1. Short Title and Table of Contents.

(a) SHORT TITLE.--This Act may be cited as the “Public Utility Regulatory Policies Act of 1978”.

(b) TABLE OF CONTENTS.--

Subtitle C--Intervention and Judicial Review

Subtitle D--Administrative Provisions

Subtitle E--State Utility Regulatory Assistance

TITLE II--CERTAIN FEDERAL ENERGY REGULATORY COMMISSION AND DEPARTMENT OF ENERGY AUTHORITIES

Sec. 2. Findings.

The Congress finds that the protection of the public health, safety, and welfare, the preservation of national security, and the proper exercise of congressional authority under the Constitution to regulate interstate commerce require--

(1) a program providing for increased conservation of electric energy, increased efficiency in the use of facilities and resources by electric utilities, and equitable retail rates for electric consumers,

(2) a program to improve the wholesale distribution of electric energy, the reliability of electric service, the procedures concerning consideration of wholesale rate applications before the Federal Energy Regulatory Commission, the participation of the public in matters before the Commission, and to provide other measures with respect to the regulation of the wholesale sale of electric energy,

(3) a program to provide for the expeditious development of hydroelectric potential at existing small dams to provide needed hydroelectric power,

(4) a program for the conservation of natural gas while insuring that rates to natural gas consumers are equitable,

(5) a program to encourage the development of crude oil transportation systems, and

(6) the establishment of certain other authorities as provided in title VI of this Act.

Sec. 3. Definitions.

As used in this Act, except as otherwise specifically provided--

(1) The term “antitrust laws” includes the Sherman Antitrust Act (15 U.S.C. 1 and following), the Clayton Act (15 U.S.C. 12 and following), the Federal Trade Commission

Act (15 U.S.C. 14 and following), the Wilson Tariff Act (15 U.S.C. 8 and 9), and the Act of June 19, 1936, chapter 592 (15 U.S.C. 13, 13a, 13b, and 21A).

(2) The term "class" means, with respect to electric consumers, any group of such consumers who have similar characteristics of electric energy use.

(3) The term "Commission" means the Federal Energy Regulatory Commission.

(4) The term "electric utility" means any person, State agency, or Federal agency, which sells electric energy.

(5) The term "electric consumer" means any person, State agency, or Federal agency, to which electric energy is sold other than for purposes of resale.

(6) The term "evidentiary hearing" means--

(A) in the case of a State agency, a proceeding which (i) is open to the public, (ii) includes notice to participants and an opportunity for such participants to present direct and rebuttal evidence and to cross-examine witnesses, (iii) includes a written decision, based upon evidence appearing in a written record of the proceeding, and (iv) is subject to judicial review;

(B) in the case of a Federal agency, a proceeding conducted as provided in sections 554, 556, and 557 of title 5, United States Code; and

(C) in the case of a proceeding conducted by any entity other than a State or Federal agency, a proceeding which conforms, to the extent appropriate, with the requirements of subparagraph (A).

(7) The term "Federal agency" means an executive agency (as defined in section 150 of title 5 of the United States Code).

(8) The term "load management technique" means any technique (other than a time-of-day or seasonal rate) to reduce the maximum kilowatt demand on the electric utility, including ripple or radio control mechanisms, and other types of interruptible electric service, energy storage devices, and load-limiting devices.

(9) The term "nonregulated electric utility" means any electric utility other than a State regulated electric utility.

(10) The term "rate" means (A) any price, rate, charge, or classification made, demanded, observed, or received with respect to sale of electric energy by an electric utility to an electric consumer, (B) any rule, regulation, or practice respecting any such rate, charge, or classification, and (C) any contract pertaining to the sale of electric energy to an electric consumer.

(11) The term “ratemaking authority” means authority to fix, modify, approve, or disapprove rates.

(12) The term “rate schedule” means the designation of the rates which an electric utility charges for electric energy.

(13) The term “sale” when used with respect to electric energy includes any exchange of electric energy.

(14) The term “Secretary” means the Secretary of Energy.

(15) The term “State” means a State, the District of Columbia, and Puerto Rico.

(16) The term “State agency” means a State, political subdivision thereof, and any agency or instrumentality of either.

(17) The term “State regulatory authority” means any State agency which has ratemaking authority with respect to the sale of electric energy by any electric utility (other than such State agency), and in the case of an electric utility with respect to which the Tennessee Valley Authority has ratemaking authority, such term means the Tennessee Valley Authority.

(18) The term “State regulated electric utility” means any electric utility with respect to which a State regulatory authority has ratemaking authority.

(19) The term “integrated resource planning” means, in the case of an electric utility, a planning and selection process for new energy resources that evaluates the full range of alternatives, including new generating capacity, power purchases, energy conservation and efficiency, cogeneration and district heating and cooling applications, and renewable energy resources, in order to provide adequate and reliable service to its electric customers at the lowest system cost. The process shall take into account necessary features for system operation, such as diversity, reliability, dispatchability, and other factors of risk; shall take into account the ability to verify energy savings achieved through energy conservation and efficiency and the projected durability of such savings measured over time; and shall treat demand and supply resources on a consistent and integrated basis.

(20) The term “system cost” means all direct and quantifiable net costs for an energy resource over its available life, including the cost of production, distribution, transportation, utilization, waste management, and environmental compliance.

(21) The term “demand side management” includes load management techniques.

Sec. 4. Relationship to Antitrust Laws.

Nothing in this Act or in any amendment made by this Act affects--

(1) the applicability of the antitrust laws to any electric utility or gas utility (as defined in section 302), or

(2) any authority of the Secretary or of the Commission under any other provision of law (including the Federal Power Act and the Natural Gas Act) respecting unfair methods of competition or anticompetitive acts or practices.

TITLE I--RETAIL REGULATORY POLICIES FOR ELECTRIC UTILITIES

Subtitle A--General Provisions

Sec. 101. Purposes.

The purposes of this title are to encourage--

(1) conservation of energy supplied by electric utilities;

(2) the optimization of the efficiency of use of facilities and resources by electric utilities; and

(3) equitable rates to electric consumers.

Sec. 102. Coverage.

(a) VOLUME OF TOTAL RETAIL SALES.--This title applies to each electric utility in any calendar year, and to each proceeding relating to each electric utility in such year, if the total sales of electric energy by such utility for purposes other than resale exceeded 500 million kilowatt-hours during any calendar year beginning after December 31, 1975, and before the immediately preceding calendar year.

(b) EXCLUSION OF WHOLESALE SALES.--The requirements of this title do not apply to the operations of an electric utility, or to proceedings respecting such operations, to the extent that such operations or proceedings relate to sales of electric energy for purposes of resale.

(c) LIST OF COVERED UTILITIES.--Before the beginning of each calendar year, the Secretary shall publish a list identifying each electric utility to which this title applies during such calendar year. Promptly after publication of such list each State regulatory authority shall notify the Secretary of each electric utility on the list for which such State regulatory authority has ratemaking authority.

Sec. 103. Federal Contracts.

Notwithstanding the limitation contained in section 102(b), no contract between a Federal agency and any electric utility for the sale of electric energy by such Federal agency for resale which is entered into or renewed after the date of the enactment of this Act may contain any provision which will have the effect of preventing the implementation of any requirement of subtitle B or C. Any provision in any such contract which has such effect shall be null and void.

Subtitle B--Standards for Electric Utilities

Sec. 111. Consideration and Determination Respecting Certain Ratemaking Standards.

(a) CONSIDERATION AND DETERMINATION.--Each State regulatory authority (with respect to each electric utility for which it has rate-making authority) and each nonregulated electric utility shall consider each standard established by subsection (d) and make a determination concerning whether or not it is appropriate to implement such standard to carry out the purposes of this title. For purposes of such consideration and determination in accordance with subsections (b) and (c), and for purposes of any review of such consideration and determination in any court in accordance with section 123, the purposes of this title supplement otherwise applicable State law. Nothing in this subsection prohibits any State regulatory authority or nonregulated electric utility from making any determination that it is not appropriate to implement any such standard, purusant to its authority under otherwise applicable State law.

(b) PROCEDURAL REQUIREMENTS FOR CONSIDERATION AND DETERMINATION.--(1) The consideration referred to in subsection (a) shall be made after public notice and hearing. The determination referred to in subsection (a) shall be--

(A) in writing,

(B) based upon findings included in such determination and upon the evidence presented at the hearing, and

(C) available to the public.

(2) Except as otherwise provided in paragraph (1), in the second sentence of section 112(a), and in sections 121 and 122, the procedures for the consideration and determination referred to in subsection (a) shall be those established by the State regulatory authority or the nonregulated electric utility.

(c) IMPLEMENTATION.--(1) The State regulatory authority (with respect to each electric utility for which it has ratemaking authority) or nonregulated electric utility may, to the extent consistent with otherwise applicable State law--

(A) implement any such standard determined under subsection (a) to be appropriate to carry out the purposes of this title, or

(B) decline to implement any such standard.

(2) If a State regulatory authority (with respect to each electric utility for which it has ratemaking authority) or nonregulated electric utility declines to implement any standard established by subsection (d) which is determined under subsection (a) to be appropriate to carry out the purposes of this title, such authority or nonregulated electric utility shall state in writing the reasons therefor. Such statement of reasons shall be available to the public.

(3) If a State regulatory authority implements a standard established by subsection (d)(7) or (8), such authority shall--

(A) consider the impact that implementation of such standard would have on small businesses engaged in the design, sale, supply, installation or servicing of energy conservation, energy efficiency or other demand side management measures, and

(B) implement such standard so as to assure that utility actions would not provide such utlities with unfair competitive advantages over such small businesses.

(d) ESTABLISHMENT.--The following Federal standards are hereby established:

(1) COST OF SERVICE.--Rates charged by any electric utility for providing electric service to each class of electric consumers shall be designed, to the maximum extent practicable, to reflect the costs of providing electric service to such class, as determined under section 115(a).

(2) DECLINING BLOCK RATES.--The energy component of a rate, or the amount attributable to the energy component in a rate, charged by any electric utility for providing electric service during any period to any class of electric consumers may not decrease as kilowatt-hour consumption by such class increases during such period except to the extent that such utility demonstrates that the costs to such utility of providing electric service to such class, which costs are attributable to such energy component, decrease as such consumption increases during such period.

(3) TIME-OF-DAY RATES.--The rates charged by any electric utility for providing electric service to each class of electric consumers shall be on a time-of-day basis which reflects the costs of providing electric service to such class of electric consumers at different times of the day unless such rates are not cost-effective with respect to such class, as determined under section 115(b).

(4) SEASONAL RATES.--The rates charged by an electric utility for providing electric service to each class of electric consumers shall be on a seasonal basis which reflects the

costs of providing service to such class of consumers at different seasons of the year to the extent that such costs vary seasonally for such utility.

(5) INTERRUPTIBLE RATES.--Each electric utility shall offer each industrial and commercial electric consumer an interruptible rate which reflects the cost of providing interruptible service to the class of which such consumer is a member.

(6) LOAD MANAGEMENT TECHNIQUES.--Each electric utility shall offer to its electric consumers such load management techniques as the State regulatory authority (or the nonregulated electric utility) has determined will--

(A) be practicable and cost-effective, as determined under section 115(c),

(B) be reliable, and

(C) provide useful energy or capacity management advantages to the electric utility.

(7) INTEGRATED RESOURCE PLANNING.--Each electric utility shall employ integrated resource planning. All plans or filings before a State regulatory authority to meet the requirements of this paragraph must be updated on a regular basis, must provide the opportunity for public participation and comment, and contain a requirement that the plan be implemented.

(8) INVESTMENTS IN CONSERVATION AND DEMAND MANAGEMENT.--The rates allowed to be charged by a State regulated electric utility shall be such that the utility's investment in and expenditures for energy conservation, energy efficiency resources, and other demand side management measures are at least as profitable, giving appropriate consideration to income lost from reduced sales due to investments in and expenditures for conservation and efficiency, as its investments in and expenditures for the construction of new generation, transmission, and distribution equipment. Such energy conservation, energy efficiency resources and other demand side management measures shall be appropriately monitored and evaluated.

(9) ENERGY EFFICIENCY INVESTMENTS IN POWER GENERATION AND SUPPLY.--The rates charged by any electric utility shall be such that the utility is encouraged to make investments in, and expenditures for, all cost-effective improvements in the energy efficiency of power generation, transmission and distribution. In considering regulatory changes to achieve the objectives of this paragraph, State regulatory authorities and nonregulated electric utilities shall consider the disincentives caused by existing ratemaking policies, and practices, and consider incentives that would encourage better maintenance, and investment in more efficient power generation, transmission and distribution equipment.

(10) CONSIDERATION OF THE EFFECTS OF WHOLESALE POWER PURCHASES ON UTILITY COST OF CAPITAL; EFFECTS OF LEVERAGED CAPITAL STRUCTURES ON THE RELIABILITY OF WHOLESALE POWER SELLERS; AND ASSURANCE OF ADEQUATE FUEL SUPPLIES.--(A) To the

extent that a State regulatory authority required or allows electric utilities for which it has ratemaking authority to consider the purchase of long-term wholesale power supplies as a means of meeting electric demand, such authority shall perform a general evaluation of:

(i) the potential for increases or decreases in the costs of capital for such utilities, and any resulting increases or decreases in the retail rates paid by electric consumers, that may result from purchases of long-term wholesale power supplies in lieu of the construction of new generation facilities by such utilities;

(ii) whether the use by exempt wholesale generators (as defined in section 32 of the Public Utility Holding Company Act of 1935) of capital structures which employ proportionally greater amounts of debt than the capital structures of such utilities threatens reliability or provides an unfair advantage for exempt wholesale generators over such utilities;

(iii) whether to implement procedures for the advance approval or disapproval of the purchase of a particular long-term wholesale power supply; and

(iv) whether to require as a condition for the approval of the purchase of power that there be reasonable assurances of fuel supply adequacy.

(B) For purposes of implementing the provisions of this paragraph, any reference contained in this section to the date of enactment of the Public Utility Regulatory Policies Act of 1978 shall be deemed to be a reference to the date of enactment of this paragraph.

(C) Notwithstanding any other provision of Federal law, nothing in this paragraph shall prevent a State regulatory authority from taking such action, including action with respect to the allowable capital structure of exempt wholesale generators, as such State regulatory authority may determine to be in the public interest as a result of performing evaluations under the standards of subparagraph (A).

(D) Notwithstanding section 124 and paragraphs (1) and (2) of section 112(a), each State regulatory authority shall consider and make a determination concerning the standards of subparagraph (A) in accordance with the requirements of subsections (a) and (b) of this section, without regard to any proceedings commenced prior to the enactment of this paragraph.

(E) Notwithstanding subsections (b) and (c) of section 112, each State regulatory authority shall consider and make a determination concerning whether it is appropriate to implement the standards set out in subparagraph (A) not later than one year after the date of enactment of this paragraph.

(11) NET METERING- Each electric utility shall make available upon request net metering service to any electric consumer that the electric utility serves. For purposes of this paragraph, the term ‘net metering service’ means service to an electric consumer under which electric energy generated by that electric consumer from an eligible on-site

generating facility and delivered to the local distribution facilities may be used to offset electric energy provided by the electric utility to the electric consumer during the applicable billing period.

(12) FUEL SOURCES- Each electric utility shall develop a plan to minimize dependence on 1 fuel source and to ensure that the electric energy it sells to consumers is generated using a diverse range of fuels and technologies, including renewable technologies.

(13) FOSSIL FUEL GENERATION EFFICIENCY- Each electric utility shall develop and implement a 10-year plan to increase the efficiency of its fossil fuel generation.

(14) TIME-BASED METERING AND COMMUNICATIONS- (A) Not later than 18 months after the date of enactment of this paragraph, each electric utility shall offer each of its customer classes, and provide individual customers upon customer request, a time-based rate schedule under which the rate charged by the electric utility varies during different time periods and reflects the variance, if any, in the utility's costs of generating and purchasing electricity at the wholesale level. The time-based rate schedule shall enable the electric consumer to manage energy use and cost through advanced metering and communications technology.

(B) The types of time-based rate schedules that may be offered under the schedule referred to in subparagraph (A) include, among others—

(i) time-of-use pricing whereby electricity prices are set for a specific time period on an advance or forward basis, typically not changing more often than twice a year, based on the utility's cost of generating and/or purchasing such electricity at the wholesale level for the benefit of the consumer. Prices paid for energy consumed during these periods shall be pre-established and known to consumers in advance of such consumption, allowing them to vary their demand and usage in response to such prices and manage their energy costs by shifting usage to a lower cost period or reducing their consumption overall;

(ii) critical peak pricing whereby time-of-use prices are in effect except for certain peak days, when prices may reflect the costs of generating and/or purchasing electricity at the wholesale level and when consumers may receive additional discounts for reducing peak period energy consumption;

(iii) real-time pricing whereby electricity prices are set for a specific time period on an advanced or forward basis, reflecting the utility's cost of generating and/or purchasing electricity at the wholesale level, and may change as often as hourly; and

(iv) credits for consumers with large loads who enter into pre-established peak load reduction agreements that reduce a utility's planned capacity obligations.

(C) Each electric utility subject to subparagraph (A) shall provide each customer requesting a time-based rate with a time-based meter capable of enabling the utility and customer to offer and receive such rate, respectively.

(D) For purposes of implementing this paragraph, any reference contained in this section to the date of enactment of the Public Utility Regulatory Policies Act of 1978 shall be deemed to be a reference to the date of enactment of this paragraph.

(E) In a State that permits third-party marketers to sell electric energy to retail electric consumers, such consumers shall be entitled to receive the same timebased metering and communications device and service as a retail electric consumer of the electric utility.

(F) Notwithstanding subsections (b) and (c) of section 112, each State regulatory authority shall, not later than 18 months after the date of enactment of this paragraph conduct an investigation in accordance with section 115(i) and issue a decision whether it is appropriate to implement the standards set out in subparagraphs (A) and (C).

(15) INTERCONNECTION- Each electric utility shall make available, upon request, interconnection service to any electric consumer that the electric utility serves. For purposes of this paragraph, the term 'interconnection service' means service to an electric consumer under which an on-site generating facility on the consumer's premises shall be connected to the local distribution facilities. Interconnection services shall be offered based upon the standards developed by the Institute of Electrical and Electronics Engineers: IEEE Standard 1547 for Interconnecting Distributed Resources with Electric Power Systems, as they may be amended from time to time. In addition, agreements and procedures shall be established whereby the services are offered shall promote current best practices of interconnection for distributed generation, including but not limited to practices stipulated in model codes adopted by associations of state regulatory agencies. All such agreements and procedures shall be just and reasonable, and not unduly discriminatory or preferential.

Sec. 112. Obligations to Consider and Determine.

(a) REQUEST FOR CONSIDERATION AND DETERMINATION.--Each State regulatory authority (with respect to each electric utility for which it has ratemaking authority) and each nonregulated electric utility may undertake the consideration and make the determination referred to in section 111 with respect to any standard established by section 111(d) in any proceeding respecting the rates of the electric utility. Any participant or intervenor (including an intervenor referred to in section 121) in such a proceeding may request, and shall obtain, such consideration and determination in such proceeding. In undertaking such consideration and making such determination in any such proceeding with respect to the application to any electric utility of any standard established by section 111(d), a State regulatory authority (with respect to an electric utility for which it has ratemaking authority) or nonregulated electric utility may take into account in such proceeding--

(1) any appropriate prior determination with respect to such standard--

(A) which is made in a proceeding which takes place after the date of the enactment of this Act, or

(B) which was made before such date (or is made in a proceeding pending on such date) and complies, as provided in section 124, with the requirements of this title; and

(2) the evidence upon which such prior determination was based (if such evidence is referenced in such proceeding).

(b) TIME LIMITATIONS.--(1) Not later than 2 years after the date of the enactment of this Act (or after the enactment of the Comprehensive National Energy Policy Act in the case of standards under paragraphs (7), (8), and (9) of section 111(d)), each State regulatory authority (with respect to each electric utility for which it has ratemaking authority) and each nonregulated electric utility shall commence the consideration referred to in section 111, or set a hearing date for such consideration, with respect to each standard established by section 111(d).

(2) Not later than three years after the date of the enactment of this Act (or after the enactment of the Comprehensive National Energy Policy Act in the case of standards under paragraphs (7), (8), and (9) of section 111(d)), each State regulatory authority (with respect to each electric utility for which it has ratemaking authority), and each nonregulated electric utility, shall complete the consideration, and shall make the determination, referred to in section 111 with respect to each standard established by section 111(d).

(3)(A) Not later than 2 years after the enactment of this paragraph, each State regulatory authority (with respect to each electric utility for which it has ratemaking authority) and each nonregulated electric utility shall commence the consideration referred to in section 111, or set a hearing date for such consideration, with respect to each standard established by paragraphs (11) through (13) of section 111(d).

(B) Not later than 3 years after the date of the enactment of this paragraph, each State regulatory authority (with respect to each electric utility for which it has ratemaking authority), and each nonregulated electric utility, shall complete the consideration, and shall make the determination, referred to in section 111 with respect to each standard established by paragraphs (11) through (13) of section 111(d).

(4)(A) Not later than 1 year after the enactment of this paragraph, each State regulatory authority (with respect to each electric utility for which it has ratemaking authority) and each nonregulated electric utility shall commence the consideration referred to in section 111, or set a hearing date for such consideration, with respect to the standard established by paragraph (14) of section 111(d).

(B) Not later than 2 years after the date of the enactment of this paragraph, each State regulatory authority (with respect to each electric utility for which it has ratemaking authority), and each nonregulated electric utility, shall complete the consideration, and shall make the determination, referred to in section 111 with respect to the standard established by paragraph (14) of section 111(d).

(5)(A) Not later than one year after the enactment of this paragraph, each State regulatory authority (with respect to each electric utility for which it has ratemaking authority) and each nonregulated utility shall commence the consideration referred to in section 111, or set a hearing date for consideration, with respect to the standard established by paragraph (15) of section 111(d).

(B) Not later than two years after the date of the enactment of the this [sic] paragraph, each State regulatory authority (with respect to each electric utility for which it has ratemaking authority), and each nonregulated electric utility, shall complete the consideration, and shall make the determination, referred to in section 111 with respect to each standard established by paragraph (15) of section 111(d).

(c) FAILURE TO COMPLY.--Each State regulatory authority (with respect to each electric utility for which it has ratemaking authority) and each nonregulated electric utility shall undertake the consideration, and make the determination, referred to in section 111 with respect to each standard established by section 111(d) in the first rate proceeding commenced after the date three years after the date of enactment of this Act respecting the rates of such utility if such State regulatory authority or nonregulated electric utility has not, before such date, complied with subsection (b)(2) with respect to such standard. In the case of each standard established by paragraphs (11) through (13) of section 111(d), the reference contained in this subsection to the date of enactment of this Act shall be deemed to be a reference to the date of enactment of such paragraphs (11) through (13). In the case of the standard established by paragraph (14) of section 111(d), the reference contained in this subsection to the date of enactment of this Act shall be deemed to be a reference to the date of enactment of such paragraph (14). In the case of the standard established by paragraph (15), the reference contained in this subsection to the date of enactment of this Act shall be deemed to be a reference to the date of enactment of paragraph (15).

(d) PRIOR STATE ACTIONS- Subsections (b) and (c) of this section shall not apply to the standards established by paragraphs (11) through (13) of section 111(d) in the case of any electric utility in a State if, before the enactment of this subsection—

(1) the State has implemented for such utility the standard concerned (or a comparable standard);

(2) the State regulatory authority for such State or relevant nonregulated electric utility has conducted a proceeding to consider implementation of the standard concerned (or a comparable standard) for such utility; or

(3) the State legislature has voted on the implementation of such standard (or a comparable standard) for such utility.

(e) PRIOR STATE ACTIONS- Subsections (b) and (c) of this section shall not apply to the standard established by paragraph (14) of section 111(d) in the case of any electric utility in a State if, before the enactment of this subsection—

(1) the State has implemented for such utility the standard concerned (or a comparable standard);

(2) the State regulatory authority for such State or relevant nonregulated electric utility has conducted a proceeding to consider implementation of the standard concerned (or a comparable standard) for such utility within the previous 3 years; or

(3) the State legislature has voted on the implementation of such standard (or a comparable standard) for such utility within the previous 3 years.

(f) PRIOR STATE ACTIONS - Subsections (b) and (c) of this section shall not apply to the standard established by paragraph (15) of section 111(d) in the case of any electric utility in a State if, before the enactment of this subsection—

(1) the State has implemented for such utility the standard concerned (or a comparable standard);

(2) the State regulatory authority for such State or relevant nonregulated electric utility has conducted a proceeding to consider implementation of the standard concerned (or a comparable standard) for such utility; or

(3) the State legislature has voted on the implementation of such standard (or a comparable standard) for such utility.

Sec. 113. Adoption of Certain Standards.

(a) ADOPTION OF STANDARDS.--Not later than two years after the date of the enactment of this Act, each State regulatory authority (with respect to each electric utility for which it has ratemaking authority), and each nonregulated electric utility, shall provide public notice and conduct a hearing respecting the standards established by subsection (b) and, on the basis of such hearing, shall--

(1) adopt the standards established by subsection (b) (other than paragraph (4) thereof) if, and to the extent, such authority or nonregulated electric utility determines that such adoption is appropriate to carry out the purposes of this title, is otherwise appropriate, and is consistent with otherwise applicable State law, and

(2) adopt the standard established by subsection (b)(4) if, and to the extent, such authority or nonregulated electric utility determines that such adoption is appropriate and consistent with otherwise applicable State law.

For purposes of any determination under paragraphs (1) or (2) and any review of such determination in any court in accordance with section 123, the purposes of this title supplement otherwise applicable State law. Nothing in this subsection prohibits any State regulatory authority or nonregulated electric utility from making any determination that it is not appropriate to adopt any such standard, pursuant to its authority under otherwise applicable State law.

(b) ESTABLISHMENT.--The following Federal standards are hereby established:

(1) MASTER METERING.--To the extent determined appropriate under section 115(d), master metering of electric service in the case of new buildings shall be prohibited or restricted to the extent necessary to carry out the purposes of this title.

(2) AUTOMATIC ADJUSTMENT CLAUSES.--No electric utility may increase any rate pursuant to an automatic adjustment clause unless such clause meets the requirements of section 115(e).

(3) INFORMATION TO CONSUMERS.--Each electric utility shall transmit to each of its electric consumers information regarding rate schedules in accordance with the requirements of section 115(f).

(4) PROCEDURES FOR TERMINATION OF ELECTRIC SERVICE.--No electric utility may terminate electric service to any electric consumer except pursuant to procedures described in section 115(g).

(5) ADVERTISING.--No electric utility may recover from any person other than the shareholders (or other owners) of such utility any direct or indirect expenditure by such utility for promotional or political advertising as defined in section 115(h).

(c) PROCEDURAL REQUIREMENTS.--Each State regulatory authority (with respect to each electric utility for which it has ratemaking authority) and each nonregulated electric utility, within the two-year period specified in subsection (a), shall (1) adopt, pursuant to subsection (a), each of the standards established by subsection (b) or, (2) with respect to any such standard which is not adopted, such authority or nonregulated electric utility shall state in writing that it has determined not to adopt such standard, together with the reasons for such determination. Such statement of reasons shall be available to the public.

Sec. 114. Lifeline Rates.

(a) LOWER RATES.--No provision of this title prohibits a State regulatory authority (with respect to an electric utility for which it has ratemaking authority) or a nonregulated electric utility from fixing, approving, or allowing to go into effect a rate foe essential needs (as defined by the State regulatory authority or by the nonregulated electric utility, as the case may be) of residential electric consumers which is lower than a rate under the standard referred to in section 111(d)(1).

(b) DETERMINATION.--If any State regulated electric utility or nonregulated electric utility does not have a lower rate as described in subsection (a) in effect two years after the date of the enactment of this Act, the State regulatory authority having ratemaking authority with respect to such State regulated electric utility or the nonregulated electric utility, as the case may be, shall determine, after an evidentiary hearing, whether such a rate should be implemented by such utility.

(c) PRIOR PROCEEDINGS.--Section 124 shall not apply to the requirements of this section.

Sec. 115. Special Rules for Standards.

(a) COST OF SERVICE.--In undertaking the consideration and making the determination under section 111 with respect to the standard concerning cost of service established by section 111(d)(1), the costs of providing electric service to each class of electric consumers shall, to the maximum extent practicable, be determined on the basis of methods prescribed by the State regulatory authority (in the case of a State regulated electric utility) or by the electric utility (in the case of a nonregulated electric utility). Such methods shall to the maximum extent practicable--

(1) permit identification of differences in cost-incurrence, for each such class of electric consumers, attributable to daily and seasonal time of use of service and

(2) permit identification of differences in cost-incurrence attributable to differences in customer demand, and energy components of cost. In prescribing such methods, such State regulatory authority or nonregulated electric utility shall take into account the extent to which total costs to an electric utility are likely to change if--

(A) additional capacity is added to meet peak demand relative to base demand; and

(B) additional kilowatt-hours of electric energy are delivered to electric consumers.

(b) TIME-OF-DAY RATES.--In undertaking the consideration and making the determination required under section 111 with respect to the standard for time-of-day rates established by section 111(d)(3), <u>and the standard for timebased metering and communications established by section 111(d)(14)</u> a time-of-day rate charged by an electric utility for providing electric service to each class of electric consumers shall be determined to be cost-effective with respect to each such class if the long-run benefits of such rate to the electric utility and its electric consumers in the class concerned are likely to exceed the metering <u>and communications</u> costs and other costs associated with the use of such rates.

(c) LOAD MANAGEMENT TECHNIQUES.--In undertaking the consideration and making the determination required under section 111 with respect to the standard for load management techniques established by section 111(d)(6), a load management technique shall be determined, by the State regulatory authority or nonregulated electric utility, to be cost-effective if--

(1) such technique is likely to reduce maximum kilowatt demand on the electric utility, and

(2) the long-run cost-savings to the utility of such reduction are likely to exceed the long-run costs to the utility associated with implementation of such technique.

(d) MASTER METERING.--Separate metering shall be determined appropriate for any new building for purposes of section 113(b)(1) if--

(1) there is more than one unit in such building,

(2) the occupant of each such unit has control over a portion of the electric energy used in such unit, and

(3) with respect to such portion of electric energy used in such unit, the long-run benefits to the electric consumers in such building exceed the costs of purchasing and installing separate meters in such building.

(e) AUTOMATIC ADJUSTMENT CLAUSES.--(1) An automatic adjustment clause of an electric utility meets the requirements of this subsection if--

(A) such clause is determined, not less often than every four years, by the State regulatory authority (with respect to an electric utility for which it has ratemaking authority) or by the electric utility (in the case of a nonregulated electric utility), after an evidentiary hearing, to provide incentives for efficient use of resources (including incentives for economical purchase and use of fuel and electric energy) by such electric utility, and

(B) such clause is reviewed not less often than every two years, in the manner described in paragraph (2), by the State regulatory authority having ratemaking authority with respect to such utility (or by the electric utility in the case of a nonregulated electric utility), to insure the maximum economies in those operations and purchases which affect the rates to which such clause applies.

(2) In making a review under subparagraph (B) of paragraph (1) with respect to an electric utility, the reviewing authority shall examine and, if appropriate, cause to be audited the practices of such electric utility relating to costs subject to an automatic adjustment clause, and shall require such reports as may be necessary to carry out such review (including a disclosure of any ownership or corporate relationship between such electric utility and the seller to such utility of fuel, electric energy, or other items).

(3) As used in this subsection and section 113(b), the term “automatic adjustment clause” means a provision of a rate schedule which provides for increases or decreases

(or both), without prior hearing, in rates reflecting increases or decreases (or both) in costs incurred by an electric utility. Such term does not include an interim rate which takes effect subject to a later determination of the appropriate amount of the rate.

(f) INFORMATION TO CONSUMERS.--(1) For purposes of the standard for information to consumers established by section 113(b)(3), each electric utility shall transmit to each of its electric consumers a clear and concise explanation of the existing rate schedule and any rate schedule applied for (or proposed by a nonregulated electric utility) applicable to such consumer. Such statement shall be transmitted to each such consumer--

(A) not later than sixty days after the date of commencement of service to such consumer or ninety days after the standard established by section 113(b)(3) is adopted with respect to such electric utility, whichever last occurs, and

(B) not later than thirty days (sixty days in the case of an electric utility which uses a bimonthly billing system) after such utility's application for any change in a rate schedule applicable to such consumer (or proposal of such a change in the case of a nonregulated utility).

(2) For purposes of the standard for information to consumers established by section 113(b)(3), each electric utility shall transmit to each of its electric consumers not less frequently than once each year--

(A) a clear and concise summary of the existing rate schedules applicable to each of the major classes of its electric consumers for which there is a separate rate, and

(B) an identification of any classes whose rates are not summarized.

Such summary may be transmitted together with such consumer's billing or in such other manner as the State regulatory authority or nonregulated electric utility deems appropriate.

(3) For purposes of the standard for information to consumers established by section 113(b)(3), each electric utility, on request of an electric consumer of such utility, shall transmit to such consumer a clear and concise statement of the actual consumption (or degree-day adjusted consumption) of electric energy by such consumer for each billing period during the prior year (unless such consumption data is not reasonably ascertainable by the utility).

(g) PROCEDURES FOR TERMINATION OF ELECTRIC SERVICE.--The procedures for termination of service referred to in section 113(b)(4) are procedures prescribed by the State regulatory authority (with respect to electric utilitics for which it has ratemaking authority) or by the nonregulated electric utility which provide that--

(1) no electric service to an electric consumer may be terminated unless reasonable prior notice (including notice of rights and remedies) is given to such consumer and such consumer has a reasonable opportunity to dispute the reasons for such termination, and

(2) during any period when termination of service to an electric consumer would be especially dangerous to health, as determined by the State regulatory authority (with respect to an electric utility for which it has ratemaking authority) or nonregulated electric utility, and such consumer establishes that--

(A) he is unable to pay for such service in accordance with the requirements of the utility's billing, or

(B) he is able to pay for such service but only in installments,

such service may not be terminated.

Such procedures shall take into account the need to include reasonable provisions for elderly and handicapped consumers.

(h) ADVERTISING.--(1) For purposes of this section and section 113 (b)(5)--

(A) The term "advertising" means the commercial use, by an electric utility, of any media, including newspaper, printed matter, radio, and television, in order to transmit a message to a substantial number of members of the public or to such utility's electric consumers.

(B) The term "political advertising" means any advertising for the purpose of influencing public opinion with respect to legislative, administrative, or electoral matters, or with respect to any controversial issue of public importance.

(C) The term "promotional advertising" means any advertising for the purpose of encouraging any person to select or use the service or additional service of an electric utility or the selection or installation of any appliance or equipment designed to use such utility's service.

(2) For purposes of this subsection and section 113(b)(5), the terms "political advertising" and "promotional advertising" do not include--

(A) Advertising which informs electric consumers how they can conserve energy or can reduce peak demand for electric energy,

(B) advertising required by law or regulation, including advertising required under part 1 of title II of the National Energy Conservation Policy Act,

(C) advertising regarding service interruptions, safety measures, or emergency conditions,

(D) advertising concerning employment opportunities with such utility,

(E) advertising which promotes the use of energy efficient appliances, equipment or services, or

(F) any explanation or justification of existing or proposed rate schedules, or notifications of hearings thereon.

(i) TIME-BASED METERING AND COMMUNICATIONS- In making a determination with respect to the standard established by section 111(d)(14), the investigation requirement of section 111(d)(14)(F) shall be as follows: Each State regulatory authority shall conduct an investigation and issue a decision whether or not it is appropriate for electric utilities to provide and install time-based meters and communications devices for each of their customers which enable such customers to participate in time-based pricing rate schedules and other demand response programs.

Sec. 116. Reports Respecting Standards.

(a) STATE AUTHORITIES AND NONREGULATED UTILITIES.--Not later than one year after the date of the enactment of this Act and annually thereafter for ten years, each State regulatory authority (with respect to each State regulated electic utility for which it has ratemaking authority), and each nonregulated electric utility, shall report to the Secretary, in such manner as the Secretary shall prescribe, respecting its consideration of the standards established by sections 111(d) and 113(b). Such report shall include a summary of the determinations made and actions taken with respect to each such standard on a utility-by-utility basis.

(b) SECRETARY.--Not later than eighteen months after the date of the enactment of this Act and annually thereafter for ten years, the Secretary shall submit a report to the President and the Congress containing--

(1) a summary of the reports submitted under subsection (a).

(2) his analysis of such reports, and

(3) his actions under this title, and his recommendations for such further Federal actions, including any legislation, regarding retail electric utility rates (and other practices) as may be necessary to carry out the purposes of this title.

Sec. 117. Relationship to State Law.

(a) REVENUE AND RATE OF RETURN.--Nothing in this title shall authorize or require the recovery by an electric utility of revenues, or of a rate of return, in excess of, or less than, the amount of revenues or the rate of return determined to be lawful under any other provision of law.

(b) STATE AUTHORITY.--Nothing in this title prohibits any State regulatory authority or nonregulated electric utility from adopting, pursuant to State law, any standard or rule affecting electric utilities which is different from any standard established by this subtitle.

(c) FEDERAL AGENCIES.--With respect to any electric utility which is a Federal agency, and with respect to the Tennessee Valley Authority when it is treated as a State regulatory authority as provided in section 3(17), any reference in section 111 or 113 to State law shall be treated as a reference to Federal law.

Subtitle C--Intervention and Judicial Review

Sec. 121. Intervention in Proceedings.

(a) AUTHORITY TO INTERVENE AND PARTICIPATE.--In order to initiate and participate in the consideration of one or more of the standards established by subtitle B or other concepts which contribute to the achievement of the purposes of this title, the Secretary, any affected electric utility, or any electric consumer of an affected electric utility may intervene and participate as a matter of right in any ratemaking proceeding or other appropriate regulatory proceeding relating to rates or rate design which is conducted by a State regulatory authority (with respect to an electric utility for which it has ratemaking authority) or by a nonregulated electric utility.

(b) ACCESS TO INFORMATION.--Any intervenor or participant in a proceeding described in subsection (a) shall have access to information available to other parties to the proceeding if such information is relevant to the issues to which his intervention or participation in such proceeding relates. Such information may be obtained through reasonable rules relating to discovery of information prescribed by the State regulatory authority (in the case of proceedings concerning electric utilities for which it has ratemaking authority) or by the nonregulated electric utility (in the case of a proceeding conducted by a nonregulated electric utility).

(c) EFFECTIVE DATE; PROCEDURES.--Any intervention or participation under this section, in any proceeding commenced before the date of the enactment of this Act but not completed before such date, shall be permitted under this section only to the extent such intervention or participation is timely under otherwise applicable law.

Sec. 122. Consider Representation.

(a) COMPENSATION FOR COSTS OF PARTICIPATION OR INTERVENTION.--(1) If no alternative means of assuring representation of electric consumers is adopted in accordance with subsection (b) and if an electric consumer of an electric utility substantially contributed to the approval, in whole or in part, of a position advocated by such consumer in a proceeding concerning such utility, and relating to any standard set forth in subtitle B, such utility shall be liable to compensate such consumer (pursuant to pargraph (2)) for reasonable attorneys' fees, expert witness fees, and other reasonable costs incurred in preparation and advocacy of such position in such proceeding (including fees and costs of obtaining judicial review of any determination made in such proceeding with respect to such position).

(2) A consumer entitled to fees and costs under paragraph (1) may collect such fees and costs from an electric utility by bringing a civil action in any State court of competent jurisdiction, unless the State regulatory authority (in the case of a proceeding concerning a State regulated electric utility) or nonregulated electric utility (in the case of a proceeding concerning such nonregulated electric utility) has adopted a reasonable procedure pursuant to which such authority or nonregulated electric utility--

(A) determines the amount of such fees and costs, and

(B) includes an award of such fees and costs in its order in the proceeding.

(3) The procedure adopted by such State regulatory authority or nonregulated utility under paragraph (2) may include a preliminary proceeding to require that--

(A) as a condition of receiving compensation under such procedure such consumer demonstrate that, but for the ability to receive such award, participation or intervention in such proceeding may be a significant financial hardship for such consumer, and

(B) persons with the same or similar interests have a common legal representative in the proceeding as a condition to receiving compensation.

(b) ALTERNATIVE MEANS.--Compensation shall not be required under subsection (a) if the State, the State regulatory authority (in the case of a proceeding concerning a State regulated electric utility), or the nonregulated electric utility (in the case of a proceeding concerning such nonregulated electric utility) has provided an alternative means for providing adequate compensation to persons--

(1) who have, or represent, an interest--

(A) which would not otherwise be adequately represented in the proceeding, and

(B) representation of which is necessary for a fair determination in the proceeding, and

(2) who are, or represent an interest which is, unable to effectively participate or intervene in the proceeding because such persons cannot afford to pay reasonable attorneys' fees, expert witness fees, and other reasonable costs of preparing for, and participating or intervening in, such proceeding (including fees and costs of obtaining judicial review of such proceeding).

(c) TRANSCRIPTS.--The State regulatory authority or nonregulated electric utility, as the case may be, shall make transcripts of the proceeding available, at cost of reproduction, to parties or intervenors in any ratemaking proceeding, or other regulatory proceeding relating to rates or rate design, before a State regulatory authority or nonregulated electric utility.

(d) FEDERAL AGENCIES.--Any claim under this section against any Federal agency shall be subject to the availability of appropriated funds.

(e) RIGHTS UNDER OTHER AUTHORITY.--Nothing in this section affects or restricts any rights of any participant or intervenor in any proceeding under any other applicable law or rule of law.

SEC. 123. JUDICIAL REVIEW AND ENFORCEMENT.

(a) LIMITATION OF FEDERAL JURISDICTION.--Notwithstanding any other provision of law, no court of the United States shall have jurisdiction over any action arising under any provision of subtitle A or B or of this subtitle except for--

(1) an action over which a court of the United States has jurisdiction under subsection (b) or (c)(2); and

(2) review of any action in the Supreme Court of the United States in accordance with sections 1257 and 1258 of title 28 of the United States Code.

(b) ENFORCEMENT OF INTERVENTION RIGHT.--(1) The Secretary may bring an action in any appropriate court of the United States to enforce his right to intervene and participate under section 121(a), and such court shall have jurisdiction to grant appropriate relief.

(2) If any electric utility or electric consumer having a right to intervene under section 121(a) is denied such right by any State court, such electric utility or electric consumer may bring an action in the appropriate United States district court to require the State regulatory authority or nonregulated electric utility to permit such intervention and participation, and such court shall have jurisdiction to grant appropriate relief.

(3) Nothing in this subsection prohibits any person bringing any action under this subsection in a court of the United States from seeking review and enforcement at any time in any State court of any rights he may have with respect to any motion to intervene or participate in any proceeding.

(c) REVIEW AND ENFORCEMENT.--(1) Any person (including the Secretary) may obtain review of any determination made under subtitle A or B or under this subtitle with respect to any electric utility (other than a utility which is a Federal agency) in the appropriate State court if such person (or the Secretary) intervened or otherwise participated in the original proceeding or if State law otherwise permits such review. Any person (including the Secretary) may bring an action to enforce the requirements of this title in the appropriate State court, except that no such action may be brought in a State court with respect to a utility which is a Federal agency. Such review or action in a State court shall be pursuant to any applicable State procedures.

(2) Any person (including the Secretary) may obtain review in the appropriate court of the United States of any determination made under subtitle A or B or this subtitle by a Federal agency if such person (or the Secretary) intervened or otherwise participated in the original proceeding or if otherwise applicable law permits such review. Such court shall have jurisdiction to grant appropriate relief. Any person (including the Secretary) may bring an action to enforce the requirements of subtitle A or B or this subtitle with respect to any Federal agency in the appropriate court of the United States and such court shall have jurisdiction to grant appropriate relief.

(3) In addition to his authority to obtain review under paragraph (1) or (2), the Secretary may also participate as an amicus curiae in any review by any court of an action arising under the provisions of subtitle A or B or this subtitle.

(d) OTHER AUTHORITY OF THE SECRETARY.--Nothing in this section prohibits the Secretary from--

(1) intervening and participating in any proceeding, or

(2) intervening and participating in any review by any court of any action

under section 204 of the Energy Conservation and Production Act.

SEC. 124. PRIOR AND PENDING PROCEEDINGS.

For purposes of subtitles A and B, and this subtitle, proceedings commenced by State regulatory authorities (with respect to electric utilities for which it has ratemaking authority) and nonregulated electric utilities before the date of the enactment of this Act and actions taken before such date in such proceedings shall be treated as complying with the requirements of subtitles A and B, and this subtitle if such proceedings and actions substantially conform to such requirements. For purposes of subtitles A and B, and this subtitle, any such proceeding or action commenced before the date of enactment of this Act, but not completed before such date, shall comply with the requirements of subtitles A and B, and this subtitle, to the maximum extent practicable, with respect to so much of such proceeding or action as takes place after such date, except as otherwise provided in section 121(c). In the case of each standard established by paragraphs (11) through (13) of section 111(d), the reference contained in this subsection to the date of enactment of this Act shall be deemed to be a reference to the date of enactment of such paragraphs (11) through (13). In the case of the standard established by paragraph (14) of section 111(d), the reference contained in this subsection to the date of enactment of this Act shall be deemed to be a reference to the date of enactment of such paragraph (14). In the case of each standard established by paragraph (15) of section 111(d), the reference contained in this subsection to the date of enactment of the Act shall be deemed to be a reference to the date of enactment of paragraph (15).

Subtitle D--Administrative Provisions

SEC. 131. VOLUNTARY GUIDELINES.

The Secretary may prescribe voluntary guidelines respecting the standards established by sections 111(d) and 113(b). Such guidelines may not expand the scope or legal effect of such standards or establish additional standards respecting electric utility rates.

SEC. 132. RESPONSIBILITIES OF SECRETARY OF ENERGY.

(a) AUTHORITY.--The Secretary may periodically notify the State regulatory authorities, and electric utilities identified pursuant to section 102(c), of--

(1) load management techniques and the results of studies and experiments concerning load management techniques;

(2) developments and innovations in electric utility ratemaking throughout the United States, including the results of studies and experiments in rate structure and rate reform;

(3) methods for determining cost of service;~~ and~~

(4) any other data or information which the Secretary determines would assist such authorities and utilities in carrying out the provisions of this title~~.~~; and

(5) technologies, techniques, and rate-making methods related to advanced metering and communications and the use of these technologies, techniques and methods in demand response programs.

(b) TECHNICAL ASSISTANCE.--The Secretary may provide such technical assistance as he determines appropriate to assist the State regulatory authorities in carrying out their responsibilities under subtitle B and as is requested by any State regulatory authority relating to the standards established by subtitle B.

(c) Appropriations.--There are authorized to be appropriated to carry out the purposes of subsection (b) not to exceed $1,000,000 for each of the fiscal years 1979 and 1980.

(d) DEMAND RESPONSE- The Secretary shall be responsible for—

(1) educating consumers on the availability, advantages, and benefits of advanced metering and communications technologies, including the funding of demonstration or pilot projects;

(2) working with States, utilities, other energy providers and advanced metering and communications experts to identify and address barriers to the adoption of demand response programs; and

(3) not later than 180 days after the date of enactment of the Energy Policy Act of 2005, providing Congress with a report that identifies and quantifies the national benefits of demand response and makes a recommendation on achieving specific levels of such benefits by January 1, 2007.

SEC. 133. GATHERING INFORMATION ON COSTS OF SERVICE.

(a) INFORMATION REQUIRED TO BE GATHERED.--Each electric utility shall periodically gather information under such rules (promulgated by the Commission) as the Commission determines necessary to allow determination of the costs associated with providing electric service. For purposes of this section, and for purposes of any consideration and determination respecting the standard established by section 111(d)(2), such costs shall be separated, to the maximum extent practicable, into the following components: customer cost component, demand cost component, and energy cost component. Rules under this subsection shall include requirements for the gathering of the following information with respect to each electric utility--

(1) the costs of serving each electric consumer class, including costs of serving different consumption patterns within such class, based on voltage level, time of use, and other appropriate factors;

(2) daily kilowatt demand load curves for all electric consumer classes combined representative of daily and seasonal differences in demand, and daily kilowatt demand load curves for each electric consumer class for which there is a separate rate, representative of daily and seasonal differences in demand;

(3) annual capital, operating, and maintenance costs--

(A) for transmission and distribution services, and

(B) for each type of generating unit; and

(4) costs of purchased power, including representative daily and seasonal differences in the amount of such costs. Such rules shall provide that information required to be gathered under this section shall be presented in such categories and such detail as may be necessary to carry out the purposes of this section.

(b) COMMISSION RULES.--The Commission shall, within 180 days after the date of enactment of this Act, by rule, prescribe the methods, procedure, and format to be used by electric utilities in gathering the information described in this section. Such rules may provide for the exemption by the Commission of an electric utility or class of electric utilities from gathering all or part of such information, in cases where such utility or utilities show and the Commission finds, after public notice and opportunity for the presentation of written data, views, and arguments, that gathering such information is not likely to carry out the purposes of this section. The Commission shall periodically review such findings and may revise such rules.

(c) FILING AND PUBLICATION.--Not later than two years after the date of enactment of this Act, and periodically, but not less frequently than every two years thereafter, each electric utility shall file with--

(1) the Commission, and

(2) any State regulatory authority which has ratemaking authority for such utility,

the information gathered pursuant to this section and make such information available to the public in such form and manner as the Commission shall prescribe. In addition, at the time of application for, or proposal of, any rate increase, each electric utility shall make such information available to the public in such form and manner as the Commission shall prescribe. The two-year period after the date of the enactment specified in this subsection may be extended by the Commission for a reasonable additional period in the case of any electric utility for good cause shown.

(d) ENFORCEMENT.--For purposes of enforcement, any violation of a requirement of this section shall be treated as a violation of a provision of the Energy Supply and Environmental Coordination Act of 1974 enforceable under section 12 of such Act (notwithstanding any expiration date in such Act) except that in applying the provisions of such section 12 any reference to the Federal Energy Administrator shall be treated as a reference to the Commission.

SEC. 134. RELATIONSHIP TO OTHER AUTHORITY.

Nothing in this title shall be construed to limit or affect any authority of the Secretary or the Commission under any other provision of law.

Subtitle E--State Utility Regulatory Assistance

SEC. 141. GRANTS TO CARRY OUT TITLES I AND III.

Section 207 of title II of the Energy Conservation and Production Act is amended to read as follows:

“STATE UTILITY REGULATORY ASSISTANCE

“Sec. 207. (a) The Secretary may make grants to State utility regulatory commissions and nonregulated electric utilities (as defined in the Public Utility Regulatory Policies Act of 1978) to carry out duties and responsibilities under titles I and III, and section 210, of the Public Utility Regulatory Policies Act of 1978. No grant may be made under this section to any Federal agency.

“(b) Any requirements established by the Secretary with respect to grants under this section may be only such requirements as are necessary to assure that such grants are expended solely to carry out duties and responsibilities referred to in subsection (a) or such as are otherwise required by law.

“(c) No grant may be made under this section unless an application for such grant is submitted to the Secretary in such form and manner as the Secretary may require. The Secretary may not approve an application of a State utility regulatory commission or nonregulated electric utility unless such commission or nonregulated electric utility assures the Secretary that funds made available under this section will be in addition to, and not in substitution for, funds made available to such commission or nonregulated electric utility from other governmental sources.

“(d) The funds appropriated for purposes of this section shall be apportioned among the States in such manner that grants made under this section in each State shall not exceed the lesser of--

“(1) the amount determined by dividing equally among all States the total amount available under this section for such grants, or

“(2) the amount which the Secretary is authorized to provide pursuant to subsections (b) and (c) of this section for such State.” .

SEC. 142. AUTHORIZATIONS.

Title II of the Energy Conservation and Production Act is amended by adding the following at the end thereof:

“AUTHORIZATION OF APPROPRIATIONS

“Sec. 208. There are authorized to be appropriated--

“(1) not to exceed $40,000,000 for each of the fiscal years 1979 and 1980 to carry out section 207 (relating to State utility regulatory assistance);

"(2) not to exceed $10,000,000 for each of the fiscal years 1979 and 1980 to carry out section 205 (relating to State offices of consumer services); and

"(3) not to exceed $8,000,000 for the fiscal year 1979, and $10,000,000 for the fiscal year 1980 to carry out section 204(1)(B) (relating to innovative rate structures)." .

SEC. 143. CONFORMING AMENDMENTS.

(a) ADMINISTRATOR.--Title II of the Energy Conservation and Production Act is amended by striking out "Administrator" in each place it appears and substituting "Secretary" . Section 202(1) of the Energy Conservation and Production Act is amended to read as follows:

"(b) DEFINITION.--

"(1) The term 'Secretary' means the Secretary of Energy." .

TITLE II--CERTAIN FEDERAL ENERGY REGULATORY COMMISSION AND DEPARTMENT OF ENERGY AUTHORITIES

SEC. 201. DEFINITIONS.

Section 3 of the Federal Power Act is amended by inserting the following before the period at the end thereof:

"(17)(A) 'small power production facility' means a facility which--

"(i) produces electric energy solely by the use, as a primary energy source, of biomass, waste, renewable resources, or any combination thereof; and

"(ii) has a power production capacity which, together with any other facilities located at the same site (as determined by the Commission), is not greater than 80 megawatts;

"(B) 'primary energy source' means the fuel or fuels used for the generation of electric energy, except that such term does not include, as determined under rules prescribed by the Commission, in consultation with the Secretary of Energy--

"(i) the minimum amounts of fuel required for ignition, startup, testing, flame stabilization, and control uses, and

"(ii) the minimum amounts of fuel required to alleviate or prevent--

"(I) unanticipated equipment outages, and

“(II) emergencies, directly affecting the public health, safety, or welfare, which would result from electric power outages;

“(C) ‘qualifying small power production facility’ means a small power production facility--

“(i) which the Commission determines, by rule, meets such requirements (including requirements respecting fuel use, fuel efficiency, and reliability) as the Commission may, by rule, prescribe; and

“(ii) which is owned by a person not primarily engaged in the generation or sale of electric power (other than electric power solely from cogeneration facilities or small power production facilities);

“(D) ‘qualifying small power producer’ means the owner or operator of a qualifying small power production facility;

“(18)(A) ‘cogeneration facility’ means a facility which produces--

“(i) electric energy, and

“(ii) steam or forms of useful energy (such as heat) which are used for industrial, commercial, heating, or cooling purposes;

“(B) ‘qualifying cogeneration facility’ means a cogeneration facility which--

“(i) the Commission determines, by rule, meets such requirements (including requirements respecting minimum size, fuel use, and fuel efficiency) as the Commission may, by rule, prescribe; and

“(ii) is owned by a person not primarily engaged in the generation or sale of electric power (other than electric power solely from cogeneration facilities or small power production facilities);

“(C) ‘qualifying cogenerator’ means the owner or operator of a qualifying cogeneration facility;

“(19) ‘Federal power marketing agency’ means any agency or instrumentality of the United States (other than the Tennessee Valley Authority) which sells electric energy;

“(20) ‘evidentiary hearings’ and ‘evidentiary proceeding’ mean a proceeding conducted as provided in sections 554, 556, and 557 of title 5, United States Code;

“(21) ‘State regulatory authority’ has the same meaning as the term ‘State commission’ , except that in the case of an electric utility with respect to which the Tennessee Valley

Authority has ratemaking authority (as defined in section 3 of the Public Utility Regulatory Policies Act of 1978), such term means the Tennessee Valley Authority;

“(22) ‘electric utility’ means any person or State agency which sells electric energy; such term includes the Tennessee Valley Authority, but does not include any Federal power marketing agency” .

SEC. 202. INTERCONNECTION.

Part II of the Federal Power Act is amended by adding the following new section at the end thereof:

“CERTAIN INTERCONNECTION AUTHORITY

“Sec. 210. (a)(1) Upon application of any electric utility, Federal power marketing agency, qualifying cogenerator, or qualifying small power producer, the Commission may issue an order requiring--

“(A) the physical connection of any cogeneration facility, any small power production facility, or the transmission facilities of any electric utility, with the facilities of such applicant,

“(B) such action as may be necessary to make effective any physical connection described in subparagraph (A), which physical connection is ineffective for any reason, such as inadequate size, poor maintenance, or physical unreliability,

“(C) such sale or exchange of electric energy or other coordination, as may be necessary to carry out the purposes of any order under subparagraph (A) or (B), or

“(D) such increase in transmission capacity as may be necessary to carry out the purposes of any order under subparagraph (A) or (B).

“(2) Any State regulatory authority may apply to the Commission for an order for any action referred to in subparagraph (A), (B), (C), or (D) of paragraph (1). No such order may be issued by the Commission with respect to a Federal power marketing agency upon application of a State regulatory authority.

“(b) Upon receipt of an application under subsection (a), the Commission shall--

“(1) issue notice to each affected State regulatory authority, each affected electric utility, each affected Federal power marketing agency, each affected owner or operator of a cogeneration facility or of a small power production facility, and to the public.

“(2) afford an opportunity for an evidentiary hearing, and

“(3) make a determination with respect to the matters referred to in subsection (c).

“(c) No order may be issued by the Commission under subsection (a) unless the Commission determines that such order--

“(1) is in the public interest,

“(2) would--

“(A) encourage overall conservation of energy or capital,

“(B) optimize the efficiency of use of facilities and resources, or

“(C) improve the reliability of any electric utility system or Federal power marketing agency to which the order applies, and

“(3) meets the requirements of section 212.

“(d) The Commission may, on its own motion, after compliance with the requirements of paragraphs (1) and (2) of subsection (b), issue an order requiring any action described in subsection (a)(1) if the Commission determines that such order meets the requirements of subsection (c). No such order may be issued upon the Commission’s own motion with respect to a Federal power marketing agency.

“(e)(1) As used in this section, the term ‘facilities’ means only facilities used for the generation or transmission of electric energy.

“(2) With respect to an order issued pursuant to an application of a qualifying cogenerator or qualifying small power producer under subsection (a)(1), the term ‘facilities of such applicant’ means the qualifying cogeneration facilities or qualifying small power production facilities of the applicant, as specified in the application. With respect to an order issued pursuant to an application under subsection (a)(2), the term ‘facilities of such applicant’ means the qualifying cogeneration facilities, qualifying small power production facilities, or the transmission facilities of an electric utility, as specified in the application. With respect to an order issued by the Commission on its own motion under subsection (d), such term means the qualifying cogeneration facilities, qualifying small power production facilities, or the transmission facilities of an electric utility, as specified in the proposed order.” .

SEC. 203. WHEELING.

Part II of the Federal Power Act, as amended by section 202 of this Act, is further amended by adding the following new section at the end thereof:

“CERTAIN WHEELING AUTHORITY

“Sec. 211. (a) Any electric utility or Federal power marketing agency may apply to the Commission for an order under this subsection requiring any other electric utility to provide transmission services to the applicant (including any enlargement of transmission capacity necessary to provide such services). Upon receipt of such application, after public notice and notice to each affected State regulatory authority, each affected electric utility, and each affected Federal power marketing agency, and after affording an opportunity for an evidentiary hearing, the Commission may issue such order if it finds that such order--

“(1) is in the public interest,

“(2) would--

“(A) conserve a significant amount of energy,

“(B) significantly promote the efficient use of facilities and resources, or

“(C) improve the reliability of any electric utility system to which the order applies, and

“(3) meets the requirements of section 212.

“(b) Any electric utility, or Federal power marketing agency, which purchases electric energy for resale from any other electric utility may apply to the Commission for an order under this subsection requiring such other electric utility to provide transmission services to the applicant (including any increase in transmission capacity necessary to provide such services). Upon receipt of an application under this subsection, after public notice and notice to each affected State regulatory authority, each affected electric utility, and each affected Federal power marketing agency, and after affording an opportunity for an evidentiary hearing, the Commission may issue such an order if the Commission determines that--

“(1) such other electric utility has given actual or constructive notice that it is unwilling or unable to provide electric service to the applicant and has been requested by the applicant to provide the transmission services requested in the application under this subsection, and

“(2) such order meets the requirements of section 212.

“(c)(1) No order may be issued under subsection (a) unless the Commission determines that such order would reasonably preserve existing competitive relationships.

“(2) No order may be issued under subsection (a) or (b) which requires the electric utility subject to the order to transmit, during any period, an amount of electric energy which replaces any amount of electric energy--

“(A) required to be provided to such applicant pursuant to a contract during such period, or

“(B) currently provided to the applicant by the utility subject to the order pursuant to a rate schedule on file during such period with the Commission.

“(3) No order may be issued under the authority of subsection (a) or (b) which is inconsistent with any State law which governs the retail marketing areas of electric utilities.

“(4) No order may be issued under subsection (a) or (b) which provides for the transmission of electric energy directly to an ultimate consumer.

“(d)(1) Any electric utility ordered under subsection (a) or (b) to provide transmission services may apply to the Commission for an order permitting such electric utility to cease providing all, or any portion of, such services. After public notice, notice to each affected State regulatory authority, each affected Federal power marketing agency, and each affected electric utility, and after an opportunity for an evidentiary hearing, the Commission shall issue an order terminating or modifying the order issued under subsection (a) or (b), if the electric utility providing such transmission services has demonstrated, and the Commission has found, that--

“(A) due to changed circumstances, the requirements applicable, under this section and section 212, to the issuance of an order under subsection (a) or (b) are no longer met, or

“(B) any transmission capacity of the utility providing transmission services under such order which was, at the time such order was issued, in excess of the capacity necessary to serve its own customers is no longer in excess of the capacity necessary for such purposes.

No order shall be issued under this subsection pursuant to a finding under subparagraph (A) unless the Commission finds that such order is in the public interest.

“(2) Any order issued under this subsection terminating or modifying an order issued under subsection (a) or (b) shall--

“(A) provide for any appropriate compensation, and

“(B) provide the affected electric utilities adequate opportunity and time to--

“(i) make suitable alternative arrangements for any transmission services terminated or modified, and

“(ii) insure that the interests of ratepayers of such utilities are adequately protected.

“(3) No order may be issued under this subsection terminating or modifying any order issued under subsection (a) or (b) if the order under subsection (a) or (b) includes terms and conditions agreed upon by the parties which--

“(A) fix a period during which transmission services are to be provided under the order under subsection (a) or (b), or

“(B) otherwise provide procedures or methods for terminating or modifying such order (including, if appropriate, the return of the transmission capacity when necessary to take into account an increase, after the issuance of such order, in the needs of the electric utility subject to such order for transmission capacity).

“(e) As used in this section, the term ‘facilities’ means only facilities used for the generation or transmission of electric energy.” .

SEC. 204. GENERAL PROVISIONS REGARDING CERTAIN INTERCONNECTION AND WHEELING AUTHORITY.

(a) RESTRICTIONS AND OTHER PROVISIONS.--Part II of the Federal Power Act, as amended by sections 202 and 203 of this Act, is further amended by adding the following new section at the end thereof:

“PROVISIONS REGARDING CERTAIN ORDERS REQUIRING INTERCONNECTION OR WHEELING

“Sec. 212. (a) No order may be issued by the Commission under section 210 or subsection (a) or (b) of section 211 unless the Commission determines that such order--

“(1) is not likely to result in a reasonably ascertainable uncompensated economic loss for any electric utility, qualifying cogenerator, or qualifying small power producer, as the case may be, affected by the order;

“(2) will not place an undue burden on an electric utility, qualifying cogenerator, or qualifying small power producer, as the case may be, affected by the order;

“(3) will not unreasonably impair the reliability of any electric utility affected by the order; and

“(4) will not impair the ability of any electric utility affected by the order to render adequate service to its customers.

The determination under paragraph (1) shall be based upon a showing of the parties. The Commission shall have no authority under section 210 or 211 to compel the enlargement of generating facilities.

“(b) No order may be issued under section 210 or subsection (a) or (b) of section 211 unless the applicant for such order demonstrates that he is ready, willing, and able to reimburse the party subject to such order for--

“(1) in the case of an order under section 210, such party’s share of the reasonably anticipated costs incurred under such order, and

“(2) in the case of an order under subsection (a) or (b) of section 211--

“(A) the reasonable costs of transmission services, including the costs of any enlargement of transmission facilities, and

“(B) a reasonable rate of return on such costs, as appropriate, as determined by the Commission.

“(c)(1) Before issuing an order under section 210 or subsection (a) or (b) of section 211, the Commission shall issue a proposed order and set a reasonable time for parties to the proposed interconnection or transmission order to agree to terms and conditions under which such order is to be carried out, including the apportionment of costs between them and the compensation or reimbursement reasonably due to any of them. Such proposed order shall not be reviewable or enforceable in any court. The time set for such parties to agree to such terms and conditions may be shortened if the Commission determines that delay would jeopardize the attainment of the purposes of any proposed order. Any terms and conditions agreed to by the parties shall be subject to the approval of the Commission.

“(2)(A) If the parties agree as provided in paragraph (1) within the time set by the Commission and the Commission approves such agreement, the terms and conditions shall be included in the final order. In the case of an order under section 210, if the parties fail to agree within the time set by the Commission or if the Commission does not approve any such agreement, the Commission shall prescribe such terms and conditions and include such terms and conditions in the final order.

“(B) In the case of any order applied for under section 211, if the parties fail to agree within the time set by the Commission, the Commission shall prescribe such terms and conditions in the final order.

“(d) If the Commission does not issue any order applied for under section 210 or 211, the Commission shall, by order, deny such application and state the reasons for such denial.

“(e) No provision of section 210 or 211 shall be treated--

“(1) as requiring any person to utilize the authority of such section 210 or 211 in lieu of any other authority of law, or

“(2) as limiting, impairing, or otherwise affecting any authority of the Commission under any other provision of law.

“(f)(1) No order under section 210 or 211 requiring the Tennessee Valley Authority (hereinafter in this subsection referred to as the ‘TVA’) to take any action shall take effect for 60 days following the date of issuance of the order. Within 60 days following the issuance by the Commission of any order under section 210 or of section 211 requiring the TVA to enter into any contract for the sale or delivery of power, the Commission may on its own motion initiate, or upon petition of any aggrieved person shall initiate, an evidentiary hearing to determine whether or not such sale or delivery would result in violation of the third sentence of section 15d(a) of the Tennessee Valley Authority Act of 1933 (16 U.S.C. 831n-4), hereinafter in this subsection referred to as the TVA Act.

“(2) Upon initiation of any evidentiary hearing under paragraph (1), the Commission shall give notice thereof to any applicant who applied for and obtained the order from the Commission, to any electric utility or other entity subject to such order, and to the public, and shall promptly make the determination referred to in paragraph (1). Upon initiation of such hearing, the Commission shall stay the effectiveness of the order under section 210 or 211 until whichever of the following dates is applicable--

“(A) the date on which there is a final determination (including any judicial review thereof under paragraph (3)) that no such violation would result from such order, or

“(B) the date on which a specific authorization of the Congress (within the meaning of the third sentence of section 15d(a) of the TVA Act) takes effect.

“(3) Any determination under paragraph (1) shall be reviewable only in the appropriate court of the United States upon petition filed by any aggrieved person or municipality within 60 days after such determination, and such court shall have jurisdiction to grant appropriate relief. Any applicant who applied for and obtained the order under section 210 or 211, and any electric utility or other entity subject to such order shall have the right to intervene in any such proceeding in such court. Except for review by such court (and any appeal or other review by an appellate court of the United States), no court shall have jurisdiction to consider any action brought by any person to enjoin the carrying out of any order of the Commission under section 210 or section 211 requiring the TVA to take any action on the grounds that such action requires a specific authorization of the Congress pursuant to the third sentence of section 15d(a) of the TVA Act.” .

(b) APPLICATION OF FEDERAL POWER ACT.--(1) Section 201(b) of such Act is amended by inserting “(1)” after “(b)” , by inserting “except as provided in paragraph (2)” after “but” in the first sentence thereof, and by adding the following at the end thereof:

“(2) The provisions of sections 210, 211, and 212 shall apply to the entities described in such provisions, and such entities shall be subject to the jurisdiction of the Commission for purposes of carrying out such provisions and for purposes of applying the enforcement authorities of this Act with respect to such provisions. Compliance with any order of the Commission under the provisions of section 210 or 211, shall not make an electric utility or other entity subject to the jurisdiction of the Commission for any purposes other than the purposes specified in the preceding sentence.” .

(2) Section 201(e) of such Act is amended by inserting “(other than facilities subject to such jurisdiction solely by reason of section 210,211, or 212)” after “under this part” .

SEC. 205. POOLING.

(a) STATE LAWS.--The Commission may, on its own motion, and shall, on application of any person or governmental entity, after public notice and notice to the Governor of the affected State and after affording an opportunity for public hearing, exempt electric utilities, in whole or in part, from any provision of State law, or from any State rule or regulation, which prohibits or prevents the voluntary coordination of electric utilities, including any agreement for central dispatch, if the Commission determines that such voluntary coordination is designed to obtain economical utilization of facilities and resources in any area. No such exemption may be granted if the Commission finds that such provision of State law, or rule or regulation--

(1) is required by any authority of Federal law, or

(2) is designed to protect public health, safety, or welfare, or the environment or conserve energy or is designed to mitigate the effects of emergencies resulting from fuel shortages.

(b) POOLING STUDY.--(1) The Commission, in consultation with the reliability councils established under section 202(a) of the Federal Power Act, the Secretary, and the electric utility industry shall study the opportunities for--

(A) conservation of energy,

(B) optimization in the efficiency of use of facilities and resources, and

(C) increased reliability, through pooling arrangements. Not later than 18 months after the date of the enactment of this Act, the Commission shall submit a report containing the results of such study to the President and the Congress.

(2) The Commission may recommend to electric utilities that such utilities should voluntarily enter into negotiations where the opportunities referred to in paragraph (1) exist. The Commission shall report annually to the President and the Congress regarding any such recommendations and subsequent actions taken by electric utilities, by the Commission, and by the Secretary under this Act, the Federal Power Act, and any other provision of law. Such annual reports shall be included in the Commission’s annual report required under the Department of Energy Organization Act.

SEC. 206. CONTINUANCE OF SERVICE.

(a) AMENDMENT OF FEDERAL POWER ACT.--Section 202 of the Federal Power Act is amended by adding the following new subsection at the end thereof:

"(g) In order to insure continuity of service to customers of public utilities, the Commission shall require, by rule, each public utility to--

"(1) report promptly to the Commission and any appropriate State regulatory authorities any anticipated shortage of electric energy or capacity which would affect such utility's capability of serving its wholesale customers,

"(2) submit to the Commission, and to any appropriate State regulatory authority, and periodically revise, contingency plans respecting--

"(A) shortages of electric energy or capacity, and

"(B) circumstances which may result in such shortages, and

"(3) accommodate any such shortages or circumstances in a manner which shall--

"(A) give due consideration to the public health, safety, and welfare, and

"(B) provide that all persons served directly or indirectly by such public utility will be treated, without undue prejudice or disadvantage." .

(b) EFFECTIVE DATE.--The amendment made by subsection (a) shall not affect any proceeding of the Commission pending on the date of the enactment of this Act or any case pending on such date respecting a proceeding of the Commission.

SEC. 207. CONSIDERATION OF PROPOSED RATE INCREASES.

(a) NOTICE PERIOD.--Section 205(d) of the Federal Power Act is amended by striking out "thirty" each place it appears and substituting "sixty" .

(b) STUDY.--The chairman of the Federal Energy Regulatory Commission, in consultation with the Secretary, is directed to conduct a study of the legal requirements and administrative procedures involved in the consideration and resolution of proposed wholesale electric rate increases under the Federal Power Act for the purposes of (1) providing for expeditious handling of hearings consistent with due process, (2) preventing the imposition of successive rate increases before they have been determined by the Commission to be just and reasonable and otherwise lawful, and (3) improving procedures designed to prohibit anticompetitive or unreasonable differences in wholesale and retail rates, or both. The chairman shall report to Congress within nine months from the date of enactment of this Act on the results of the study required under this section, on the administrative actions taken as a result of this study, and on any recommendations for changes in existing law that will aid the purposes of this section.

SEC. 208. AUTOMATIC ADJUSTMENT CLAUSES.

Section 205 of the Federal Power Act is amended by adding the following new subsection at the end thereof:

"(f)(1) Not later than 2 years after the date of the enactment of this subsection and not less often than every 4 years thereafter, the Commission shall make a thorough review of automatic adjustment clauses in public utility rate schedules to examine--

"(A) whether or not each such clause effectively provides incentives for efficient use of resources (including economical purchase and use of fuel and electric energy), and

"(B) whether any such clause reflects any costs other than costs which are--

"(i) subject to periodic fluctuations and

"(ii) not susceptible to precise determinations in rate cases prior to the time such costs are incurred.

Such review may take place in individual rate proceedings or in generic or other separate proceedings applicable to one or more utilities.

"(2) Not less frequently than every 2 years, in rate proceedings or in generic or other separate proceedings, the Commission shall review, with respect to each public utility, practices under any automatic adjustment clauses of such utility to insure efficient use of resources (including economical purchase and use of fuel and electric energy) under such clauses.

"(3) The Commission may, on its own motion or upon complaint, after an opportunity for an evidentiary hearing, order a public utility to--

"(A) modify the terms and provisions of any automatic adjustment clause, or

"(B) cease any practice in connection with the clause, if such clause or practice does not result in the economical purchase and use of fuel, electric energy, or other items, the cost of which is included in any rate schedule under an automatic adjustment clause.

"(4) As used in this subsection, the term 'automatic adjustment clause' means a provision of a rate schedule which provides for increases or decreases (or both), without prior hearing, in rates reflecting increases or decreases (or both) in costs incurred by an electric utility. Such term does not include any rate which takes effect subject to refund and subject to a later determination of the appropriate amount of such rate."

SEC. 209. RELIABILITY.

(a) STUDY.--(1) The Secretary, in consultation with the Commission, shall conduct a study with respect to--

(A) the level of reliability appropriate to adequately serve the needs of electric consumers, taking into account cost effectiveness and the need for energy conservation,

(B) the various methods which could be used in order to achieve such level of reliability and the cost effectiveness of such methods, and

(C) the various procedures that might be used in case of an emergency outage to minimize the public disruption and economic loss that might be caused by such an outage and the cost effectiveness of such procedures.

Such study shall be completed and submitted to the President and the Congress not later than 18 months after the date of the enactment of this Act. Before such submittal the Secretary shall provide an opportunity for public comment on the results of such study.

(2) The study under paragraph (1) shall include consideration of the following:

(A) the cost effectiveness of investments in each of the components involved in providing adequate and reliable electric service, including generation, transmission, and distribution facilities, and devices available to the electric consumer;

(B) the environmental and other effects of the investments considered under subparagraph (A);

(C) various types of electric utility systems in terms of generation, transmission, distribution and customer mix, the extent to which differences in reliability levels may be desirable, and the cost-effectiveness of the various methods which could be used to decrease the number and severity of any outages among the various types of systems;

(D) alternatives to adding new generation facilities to achieve such desired levels of reliability (including conservation);

(E) the cost-effectiveness of adding a number of small, decentralized conventional and nonconventional generating units rather than a small number of large generating units with a similar total megawatt capacity for achieving the desired level of reliability; and

(F) any standards for electric utility reliability used by, or suggested for use by, the electric utility industry in terms of cost-effectiveness in achieving the desired level of reliability, including equipment standards, standards for operating procedures and training of personnel, and standards relating the number and severity of outages to periods of time.

(b) EXAMINATION OF RELIABILITY ISSUES BY RELIABILITY COUNCILS.--The Secretary, in consultation with the Commission, may, from time to time, request the reliability councils established under section 202(a) of the Federal Power Act or other appropriate persons (including Federal agencies) to examine and report to him concerning any electric utility reliability issue. The Secretary shall report to the Congress (in its annual report or in the report required under subsection (a) if appropriate) the results of any examination under the preceding sentence.

(c) DEPARTMENT OF ENERGY RECOMMENDATIONS.--The Secretary, in consultation with the Commission, and after opportunity for public comment, may recommend industry standards for reliability to the electric utility industry, including standards with respect to equipment, operating procedures and training of personnel, and standards relating to the level or levels of reliability appropriate to adequately and reliably serve the needs of electric consumers. The Secretary shall include in his annual report--

(1) any recommendations made under this subsection or any recommendations respecting electric utility reliability problems under any other provision of law, and

(2) a description of actions taken by electric utilities with respect to such recommendations.

Sec. 210. Cogeneration and Small Power Production.

(a) COGENERATION AND SMALL POWER PRODUCTION RULES.--Not later than 1 year after the date of enactment of this Act, the Commission shall prescribe, and from time to time thereafter revise, such rules as it determines necessary to encourage cogeneration and small power production and to encourage geothermal small power production facilities of not more than 80 megawatts capacity, which rules require electric utilities to offer to--

(1) sell electric energy to qualifying cogeneration facilities and qualifying small power production facilities and

(2) purchase electric energy from such facilities.

Such rules shall be prescribed, after consultation with representatives of Federal and State regulatory agencies having ratemaking authority for electric utilities, and after public notice and a reasonable opportunity for interested persons (including State and Federal agencies) to submit oral as well as written data, views, and arguments. Such rules shall include provisions respecting minimum reliability of qualifying cogeneration facilities and qualifying small power production facilities (including reliability of such facilities during emergencies) and rules respecting reliability of electric energy service to be available to such facilities from electric utilities during emergencies. Such rules may not authorize a qualifying cogeneration facility or qualifying small power production facility to make any sale for purposes other than resale.

(b) RATES FOR PURCHASES BY ELECTRIC UTILITIES.--The rules prescribed under subsection (a) shall insure that, in requiring any electric utility to offer to purchase electric energy from any qualifying cogeneration facility or qualifying small power production facility, the rates for such purchase--

(1) shall be just and reasonable to the electric consumers of the electric utility and in the public interest, and

(2) shall not discriminate against qualifying cogenerators or qualifying small power producers.

No such rule prescribed under subsection (a) shall provide for a rate which exceeds the incremental cost to the electric utility of alternative electric energy.

(c) RATES FOR SALES BY UTILITIES.--The rules prescribed under subsection (a) shall insure that, in requiring any electric utility to offer to sell electric energy to any qualifying cogeneration facility or qualifying small power production facility, the rates for such sale--

(1) shall be just and reasonable and in the public interest, and

(2) shall not discriminate against the qualifying cogenerators or qualifying small power producers.

(d) DEFINITION.--For purposes of this section, the term "incremental cost of alternative electric energy" means, with respect to electric energy purchased from a qualifying cogenerator or qualifying small power producer, the cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source.

(e) EXEMPTIONS.--(1) Not later than 1 year after the date of enactment of this Act and from time to time thereafter, the Commission shall, after consultation with representatives of State regulatory authorities, electric utilities, owners of cogeneration facilities and owners of small power production facilities, and after public notice and a reasonable opportunity for interested persons (including State and Federal agencies) to submit oral as well as written data, views, and arguments, prescribe rules under which geothermal small power production facilities of not more than 80 megawatts capacity, qualifying cogeneration facilities and qualifying small power production facilities are exempted in whole or part from the Federal Power Act, from the Public Utility Holding Company Act, from State laws and regulations respecting the rates, or respecting the financial or organizational regulation, of electric utilities, or from any combination of the foregoing, if the Commission determines such exemption is necessary to encourage cogeneration and small power production.

(2) No qualifying small power production facility (other than a qualifying small power production facility which is an eligible solar, wind, waste, or geothermal facility as defined in section 3(17)(E) of the Federal Power Act) which has a power production capacity which, together with any other facilities located at the same site (as determined by the Commission), exceeds 30 megawatts, or 80 megawatts for a qualifying small power production facility using geothermal energy as the primary energy source, may be exempted under rules under paragraph (1) from any provision of law or regulation referred to in paragraph (1), except that any qualifying small power production facility which produces electric energy solely by the use of biomass as a primary energy source, may be exempted by the Commission under such rules from the Public Utility Holding Company Act and from State laws and regulations referred to in such paragraph (1).

(3) No qualifying small power production facility or qualifying cogeneration facility may be exempted under this subsection from--

(A) any State law or regulation in effect in a State pursuant to subsection (f),

(B) the provisions of section 210, 211, or 212 of the Federal Power Act or the necessary authorities for enforcement of any such provision under the Federal Power Act, or

(C) any license or permit requirement under part I of the Federal Power Act, any provision under such Act related to such a license or permit requirement, or the necessary authorities for enforcement of any such requirement.

(f) IMPLEMENTATION OF RULES FOR QUALIFYING COGENERATION AND QUALIFYING SMALL POWER PRODUCTION FACILITIES.--(1) Beginning on or before the date one year after any rule is prescribed by the Commission under subsection (a) or revised under such subsection, each State regulatory authority shall, after notice and opportunity for public hearing, implement such rule (or revised rule) for each electric utility for which it has ratemaking authority.

(2) Beginning on or before the date one year after any rule is prescribed by the Commission under subsection (a) or revised under such subsection, each nonregulated electric utility shall, after notice and opportunity for public hearing, implement such rule (or revised rule).

(g) JUDICIAL REVIEW AND ENFORCEMENT.--(1) Judicial review may be obtained respecting any proceeding conducted by a State regulatory authority or nonregulated electric utility for purposes of implementing any requirement of a rule under subsection (a) in the same manner, and under the same requirements, as judicial review may be obtained under section 123 in the case of a proceeding to which section 123 applies.

(2) Any person (including the Secretary) may bring an action against any electric utility, qualifying small power producer, or qualifying cogenerator to enforce any requirement established by a State regulatory authority or nonregulated electric utility pursuant to subsection (f). Any such action shall be brought only in the manner, and under the requirements, as provided under section 123 with respect to an action to which section 123 applies.

(h) COMMISSION ENFORCEMENT.--(1) For purposes of enforcement of any rule prescribed by the Commission under subsection (a) with respect to any operations of an electric utility, a qualifying cogeneration facility or a qualifying small power production facility which are subject to the jurisdiction of the Commission under part II of the Federal Power Act, such rule shall be treated as a rule under the Federal Power Act. Nothing in subsection (g) shall apply to so much of the operations of an electric utility, a qualifying cogeneration facility or a qualifying small power production facility as are subject to the jurisdiction of the Commission under part II of the Federal Power Act.

(2)(A) The Commission may enforce the requirements of subsection (f) against any State regulatory authority or nonregulated electric utility. For purposes of any such enforcement, the requirements of subsection (f)(1) shall be treated as a rule enforceable under the Federal Power Act. For purposes of any such action, a State regulatory authority or nonregulated electric utility shall be treated as a person within the meaning of the Federal Power Act. No enforcement action may be brought by the Commission under this section other than--

(i) an action against the State regulatory authority or nonregulated electric utility for failure to comply with the requirements of subsection (f) or

(ii) an action under paragraph (1).

(B) Any electric utility, qualifying cogenerator, or qualifying small power producer may petition the Commission to enforce the requirements of subsection (f) as provided in subparagraph (A) of this paragraph. If the Commission does not initiate an enforcement action under subparagraph (A) against a State regulatory authority or non-regulated electric utility within 60 days following the date on which a petition is filed under this subparagraph with respect to such authority, the petitioner may bring an action in the appropriate United States district court to require such State regulatory authority or non-regulated electric utility to comply with such requirements and such court may issue such injunctive or other relief as may be appropriate. The Commission may intervene as a matter of right in any such action.

(i) FEDERAL CONTRACTS.--No contract between a Federal agency and any electric utility for the sale of electric energy by such Federal agency for resale which is entered into after the date of the enactment of this Act may contain any provision which will have the effect of preventing the implementation of any rule under this section with respect to such utility. Any provision in any such contract which has such effect shall be null and void.

(j) NEW DAMS AND DIVERSIONS.--Except for a hydroelectric project located at a Government dam (as defined in section 3(10) of the Federal Power Act) at which non-Federal hydroelectric development is permissible, this section shall not apply to any hydroelectric project which impounds or diverts the water of a natural watercourse by means of a new dam or diversion unless the project meets each of the following requirements:

(1) NO SUBSTANTIAL ADVERSE EFFECTS.--At the time of issuance of the license or exemption for the project, the Commission finds that the project will not have substantial adverse effects on the environment, including recreation and water quality. Such finding shall be made by the Commission after taking into consideration terms and conditions imposed under either paragraph (3) of this subsection or section 10 of the Federal Power Act (whichever is appropriate as required by that Act or the Electric Consumers Protection Act of 1986) and compliance with other environmental requirements applicable to the project.

(2) PROTECTED RIVERS.--At the time the application for a license or exemption for the project is accepted by the Commission (in accordance with the Commission's regulations and procedures in effect on January 1, 1986, including those relating to environmental consultation), such project is not located on either of the following:

(A) Any segment of a natural watercourse which is included in (or designated for potential inclusion in) a State or national wild and scenic river system.

(B) Any segment of a natural watercourse which the State has determined, in accordance with applicable State law, to possess unique natural, recreational, cultural, or scenic attributes which would be adversely affected by hydroelectric development.

(3) FISH AND WILDLIFE TERMS AND CONDITIONS.--The project meets the terms and conditions set by fish and wildlife agencies under the same procedures as provided for under section 30(c) of the Federal Power Act.

(k) DEFINITION OF NEW DAM OR DIVERSION.--For purposes of this section, the term "new dam or diversion" means a dam or diversion which requires, for purposes of installing any hydroelectric power project, any construction, or enlargement of any impoundment or diversion structure (other than repairs or reconstruction or the addition of flashboards or similar adjustable devices).

(l) Definitions.--For purposes of this section, the terms "small power production facility", "qualifying small power production facility", "qualifying small power producer", "primary energy source", "cogeneration facility", "qualifying cogeneration facility", and "qualifying cogenerator" have the respective meanings provided for such terms under section 3 (17) and (18) of the Federal Power Act.

(m) TERMINATION OF MANDATORY PURCHASE AND SALE REQUIREMENTS-

(1) OBLIGATION TO PURCHASE- After the date of enactment of this subsection, no electric utility shall be required to enter into a new contract or obligation to purchase electric energy from a qualifying cogeneration facility or a qualifying small power production facility under this section if the Commission finds that the qualifying cogeneration facility or qualifying small power production facility has nondiscriminatory access to—

(A)(i) independently administered, auction-based day ahead and real time wholesale markets for the sale of electric energy; and (ii) wholesale markets for long-term sales of capacity and electric energy; or

(B)(i) transmission and interconnection services that are provided by a Commission-approved regional transmission entity and administered pursuant to an open access transmission tariff that affords nondiscriminatory treatment to all customers; and (ii) competitive wholesale markets that provide a meaningful opportunity to sell capacity, including long-term and short-term sales, and electric energy, including long-term, short-term and real-time sales, to buyers other than the utility to which the qualifying facility is interconnected. In determining whether a meaningful opportunity to sell exists, the commission shall consider, among other factors, evidence of transactions within the relevant market; or

(C) wholesale markets for the sale of capacity and electric energy that are, at a minimum, of comparable competitive quality as markets described in subparagraphs (A) and (B).

(2) REVISED PURCHASE AND SALE OBLIGATION FOR NEW FACILITIES- (A) After the date of enactment of this subsection, no electric utility shall be required pursuant to this section to enter into a new contract or obligation to purchase from or sell electric energy to a facility that is not an existing qualifying cogeneration facility unless the facility meets the criteria for qualifying cogeneration facilities established by the Commission pursuant to the rulemaking required by subsection (n).

(B) For the purposes of this paragraph, the term `existing qualifying cogeneration facility' means a facility that—

(i) was a qualifying cogeneration facility on the date of enactment of subsection (m); or

(ii) had filed with the Commission a notice of self-certification, selfrecertification or an application for Commission certification under 18 C.F.R. 292.207 prior to the date on which the Commission issues the final rule required by subsection (n).

(3) COMMISSION REVIEW- Any electric utility may file an application with the Commission for relief from the mandatory purchase obligation pursuant to this subsection on a service territory-wide basis. Such application shall set forth the factual basis upon which relief is requested and describe why the conditions set forth in

subparagraphs (A), (B) or (C) of paragraph (1) of this subsection have been met. After notice, including sufficient notice to potentially affected qualifying cogeneration facilities and qualifying small power production facilities, and an opportunity for comment, the Commission shall make a final determination within 90 days of such application regarding whether the conditions set forth in subparagraphs (A), (B) or (C) of paragraph (1) have been met.

(4) REINSTATEMENT OF OBLIGATION TO PURCHASE- At any time after the Commission makes a finding under paragraph (3) relieving an electric utility of its obligation to purchase electric energy, a qualifying cogeneration facility, a qualifying small power production facility, a State agency, or any other affected person may apply to the Commission for an order reinstating the electric utility's obligation to purchase electric energy under this section. Such application shall set forth the factual basis upon which the application is based and describe why the conditions set forth in subparagraphs (A), (B) or (C) of paragraph (1) of this subsection are no longer met. After notice, including sufficient notice to potentially affected utilities, and opportunity for comment, the Commission shall issue an order within 90 days of such application reinstating the electric utility's obligation to purchase electric energy under this section if the Commission finds that the conditions set forth in subparagraphs (A), (B) or (C) of paragraph (1) which relieved the obligation to purchase, are no longer met.

(5) OBLIGATION TO SELL- After the date of enactment of this subsection, no electric utility shall be required to enter into a new contract or obligation to sell electric energy to a qualifying cogeneration facility or a qualifying small power production facility under this section if the Commission finds that—

(A) competing retail electric suppliers are willing and able to sell and deliver electric energy to the qualifying cogeneration facility or qualifying small power production facility; and

(B) the electric utility is not required by State law to sell electric energy in its service territory.

(6) NO EFFECT ON EXISTING RIGHTS AND REMEDIES- Nothing in this subsection affects the rights or remedies of any party under any contract or obligation, in effect or pending approval before the appropriate State regulatory authority or non-regulated electric utility on the date of enactment of this subsection, to purchase electric energy or capacity from or to sell electric energy or capacity to a qualifying cogeneration facility or qualifying small power production facility under this Act (including the right to recover costs of purchasing electric energy or capacity).

(7) RECOVERY OF COSTS- (A) The Commission shall issue and enforce such regulations as are necessary to ensure that an electric utility that purchases electric energy or capacity from a qualifying cogeneration facility or qualifying small power production facility in accordance with any legally enforceable obligation entered into or imposed under this section recovers all prudently incurred costs associated with the purchase.

(B) A regulation under subparagraph (A) shall be enforceable in accordance with the provisions of law applicable to enforcement of regulations under the Federal Power Act (16 U.S.C. 791a et seq.).

(n) RULEMAKING FOR NEW QUALIFYING FACILITIES- (1)(A) Not later than 180 days after the date of enactment of this section, the Commission shall issue a rule revising the criteria in 18 C.F.R. 292.205 for new qualifying cogeneration facilities seeking to sell electric energy pursuant to section 210 of this Act to ensure—

(i) that the thermal energy output of a new qualifying cogeneration facility is used in a productive and beneficial manner;

(ii) the electrical, thermal, and chemical output of the cogeneration facility is used fundamentally for industrial, commercial, or institutional purposes and is not intended fundamentally for sale to an electric utility, taking into account technological, efficiency, economic, and variable thermal energy requirements, as well as State laws applicable to sales of electric energy from a qualifying facility to its host facility; and

(iii) continuing progress in the development of efficient electric energy generating technology.

(B) The rule issued pursuant to paragraph (1)(A) of this subsection shall be applicable only to facilities that seek to sell electric energy pursuant to section 210 of this Act. For all other purposes, except as specifically provided in subsection (m)(2)(A), qualifying facility status shall be determined in accordance with the rules and regulations of this Act.

(2) Notwithstanding rule revisions under paragraph (1), the Commission's criteria for qualifying cogeneration facilities in effect prior to the date on which the Commission issues the final rule required by paragraph (1) shall continue to apply to any cogeneration facility that—

(A) was a qualifying cogeneration facility on the date of enactment of subsection (m), or

(B) had filed with the Commission a notice of self-certification, self-recertification or an application for Commission certification under 18 C.F.R. 292.207 prior to the date on which the Commission issues the final rule required by paragraph (1).

Sec. 211. Interlocking Directorates.

Note: Subsection (a) amended Section 305 of the Federal Power Act. See ¶5305 .

(b) EFFECTIVE DATE.--No person shall be required to file a statement under section 305(c)(1) of the Federal Power Act before April 30 of the second calendar year which begins after the date of the enactment of this Act and no public utility shall be required to publish a list under section 305(c)(2) of such Act before January 31 of such second calendar year.

Note: Section 212 amended Sections 319-321 of the Federal Power Act. See ¶5319 - 5321.

Note: Section 213 added Section 30 to Part I of the Federal Power Act. See ¶5230 .

FED-LAW, FERCSR ¶5074, **PURPA, SEC. 214. PRIOR ACTION; EFFECT ON**

Sec. 214. Prior Action; Effect on Other Authorities.

(a) PRIOR ACTIONS.--No provision of this title or of any amendment made by this title shall apply to, or affect, any action taken by the Commission before the date of the enactment of this Act.

(b) OTHER AUTHORITIES.--No provision of this title or of any amendment made by this title shall limit, impair or otherwise affect any authority of the Commission or any other agency or instrumentality of the United States under any other provision of law except as specifically provided in this title.

TITLE III--RETAIL POLICIES FOR NATURAL GAS UTILITIES

Sec. 301. Purposes; Coverage.

(a) PURPOSES.--The purposes of this title are to encourage--

(1) conservation of energy supplied by gas utilities;

(2) the optimization of the efficiency of use of facilities and resources by gas utility systems; and

(3) equitable rates to gas consumers of natural gas.

(b) VOLUME OF TOTAL RETAIL SALES.--This title applies to each gas utility in any calendar year, and to each proceeding relating to each gas utility in such year, if the total sales of natural gas by such utility for purposes other than resale exceeded 10 billion cubic feet during any calendar year beginning after December 31, 1975, and before the immediately preceding calendar year.

(c) EXCLUSION OF WHOLESALE SALES.--The requirements of this title do not apply to the operations of a gas utility, or to proceedings respecting such operations, to the extent that such operations or proceedings relate to sales of natural gas for purposes of resale.

(d) LIST OF COVERED UTILITIES.--Before the beginning of each calendar year, the Secretary shall publish a list identifying each gas utility to which this title applies during such calendar year. Promptly after publication of such list, each State regulatory authority shall notify the Secretary of each gas utility on the list for which such State regulatory authority has ratemaking authority.

Sec. 302. Definitions.

For purposes of this title--

(1) The term “gas consumer” means any person, State agency, or Federal agency, to which natural gas is sold other than for purposes of resale.

(2) The term “gas utility” means any person, State agency, or Federal agency, engaged in the local distribution of natural gas, and the sale of natural gas to any ultimate consumer of natural gas.

(3) The term “State regulated gas utility” means any gas utility with respect to which a State regulatory authority has ratemaking authority.

(4) The term “nonregulated gas utility” means any gas utility other than a State regulated gas utility.5049)]

(5) The term “rate” means any (A) price, rate, charge, or classification made, demanded, observed, or received with respect to sale of natural gas to a gas consumer, (B) any rule, regulation, or practice respecting any such rate, charge, or classification, and (C) any contract pertaining to the sale of natural gas to a gas consumer.

(6) The term “ratemaking authority” means authority to fix, modify, approve, or disapprove rates.

(7) The term “sale”, when used with respect to natural gas, includes an exchange of natural gas.

(8) The term “State regulatory authority” means any State agency which has ratemaking authority with respect to the sale of natural gas by any gas utility (other than by such State agency).

(9) The term “integrated resource planning” means, in the case of a gas utility, planning by the use of any standard, regulation, practice, or policy to undertake a

systematic comparison between demand-side management measures and the supply of gas by a gas utility to minimize life-cycle costs of adequate and reliable utility services to gas consumers. Integrated resource planning shall take into account necessary features for system operation such as diversity, reliability, dispatchability, and other factors of risk and shall treat demand and supply to gas consumers on a consistent and integrated basis.

(10) The term "demand-side management" includes energy conservation, energy efficiency, and load management techniques.

Sec. 303. Adoption of Certain Standards.

(a) ADOPTION OF STANDARDS.--Not later than 2 years after the date of the enactment of this Act (or after enactment of the Energy Policy Act of 1992 in the case of standards under paragraphs (3) and (4) of subsection (b)), each State regulatory authority (with respect to each gas utility for which it has ratemaking authority) and each nonregulated gas utility shall provide public notice and conduct a hearing respecting the standards established by subsection (b) and, on the basis of such hearing, shall--

(1) adopt the standard established by subsection (b)(1) if, and to the extent, such authority or nonregulated utility determines that such adoption is appropriate and is consistent with otherwise applicable State law, and

(2) adopt the standards established by paragraphs (2), (3) and (4) of subsection (b) if, and to the extent, such authority or nonregulated utility determines that such adoption is appropriate to carry out the purposes of this title, is otherwise appropriate, and is consistent with otherwise applicable State law.

For purposes of any determination under paragraphs (1) and (2) and any review of such determination in any court under section 307, the purposes of this title supplement State law. Nothing in this subsection prohibits any State regulatory authority or nonregulated utility from making any determination that it is not appropriate to implement any such standard, pursuant to its authority under otherwise applicable State law.

(b) ESTABLISHMENT.--The following Federal standards are hereby established:

(1) PROCEDURES FOR TERMINATION OF NATURAL GAS SERVICE.--No gas utility may terminate natural gas service to any gas consumer except pursuant to procedures described in section 304(a).

(2) ADVERTISING.--No gas utility may recover from any person other than the shareholders (or other owners) of such utility any direct or indirect expenditure by such utility for promotional or political advertising as defined in section 304(b).

(3) INTEGRATED RESOURCE PLANNING.--Each gas utility shall employ, in order to provide adequate and reliable service to its gas customers at the lowest system cost. All

plans or filings of a State regulated gas utility before a State regulatory authority to meet the requirements of this paragraph shall (A) be updated on a regular basis, (B) provide the opportunity for public participation and comment, (C) provide for methods of validating predicted performance, and (D) contain a requirement that the plan be implemented after approval of the State regulatory authority. Subsection (c) shall not apply to this paragraph to the extent that it could be construed to require the State regulatory authority to extend the record of a State proceeding in submitting reports to the Federal Government.

(4) INVESTMENTS IN CONSERVATION AND DEMAND MANAGEMENT.--The rates charged by any State regulated gas utility shall be such that the utility's prudent investments in, and expenditures for, energy conservation and load shifting programs and for other demand-side management measures which are consistent with the findings and purposes of the Energy Policy Act of 1992 are at least as profitable (taking into account the income lost due to reduced sales resulting from such programs) as prudent investments in, and expenditures for, the acquisition or construction of supplies and facilities. This objective requires that (A) regulators link the utility's net revenues, at least in part, to the utility's performance in implementing cost-effective programs promoted by this section; and (B) regulators ensure that, for purposes of recovering fixed costs, including its authorized return, the utility's performance is not affected by reductions in its retail sales volumes.

(c) PROCEDURAL REQUIREMENTS.--Each State regulatory authority (with respect to each gas utility for which it has ratemaking authority) and each nonregulated gas utility, within the 2-year period specified in subsection (a), shall adopt, pursuant to subection (a), each of the standards established by subsection (b) or, with respect to any such standard which is not adopted, such authority or nonregulated gas utility shall state in writing that it has determined not to adopt such standard, together with the reasons for such determination. Such statement of reasons shall be available to the public.

(d) SMALL BUSINESS IMPACTS.--If a State regulatory authority implements a standard established by subsection (b)(3) or (4), such authority shall--

(1) consider the impact that implementation of such standard would have on small businesses engaged in the design, sale, supply, installation, or servicing of energy conservation, energy efficiency, or other demand-side management measures, and

(2) implement such standard so as to assure that utility actions would not provide such utilities with unfair competitive advantages over such small businesses.

Sec. 304. Special Rules for Standards.

(a) PROCEDURES FOR TERMINATION OF GAS SERVICE.--The procedures for termination of service referred to in section 303(b)(1) are procedures prescribed by the State regulatory authority (with respect to gas utilities for which it has ratemaking authority) or the nonregulated gas utility which provide that--

(1) no gas service to a gas consumer may be terminated unless reasonable prior notice (including notice of rights and remedies) is given to such consumer and such consumer has a reasonable opportunity to dispute the reasons for such termination, and

(2) during any period when termination of service to a gas consumer would be especially dangerous to health, as determined by the State regulatory authority (with respect to each gas utility for which it has ratemaking authority) or nonregulated gas utility, and such consumer establishes that--

(A) he is unable to pay for such service in accordance with the requirements of the utility's billing, or

(B) he is able to pay for such service but only in installments,

such service may not be terminated.

Such procedures shall take into account the need to include reasonable provisions for elderly and handicapped consumers.

(b) ADVERTISING.--(1) For purposes of this section and section 303--

(A) The term "advertising" means the commercial use, by a gas utility, of any media, including newspaper, printed matter, radio, and television, in order to transmit a message to a substantial number of members of the public or to such utility's gas consumers.

(B) The term "political advertising" means any advertising for the purpose of influencing public opinion with respect to legislative, administrative, or electoral matters, or with respect to any controversial issue of public importance.

(C) The term "promotional advertising" means any advertising for the purpose of encouraging any person to select or use the service or additional service of a gas utility or the selection or installation of any appliance or equipment designed to use such utility's service.

(2) For purposes of this section and section 303, the terms, "political advertising" and "promotional advertising" do not include--

(A) advertising which informs natural gas consumers how they can conserve natural gas or can reduce peak demand for natural gas,

(B) advertising required by law or regulation, including advertising required under part 1 of title II of the National Energy Conservation Policy Act,

(C) advertising regarding service interruptions, safety measures, or emergency conditions,

(D) advertising concerning employment opportunities with such utility,

(E) advertising which promotes the use of energy efficient appliances, equipment or services, or

(F) any explanation or justification of existing or proposed rate schedules, or notification of hearings thereon.

Sec. 305. Federal Participation.

(a) INTERVENTION.--In addition to the authorities vested in the Secretary pursuant to any other provision of law, the Secretary, on his own motion, may intervene as a matter of right in any proceeding before a State regulatory authority which relates to gas utility rates or rate design. Such intervention shall be solely for the purpose of advocating policies or methods which carry out the purposes set forth in section 301 of this title.

(b) RIGHTS.--The Secretary shall have the same rights as any other party to a proceeding before State regulatory authority which relates to gas utility rates or rate design.

(c) NONREGULATED GAS UTILITIES.--The Secretary, on his own motion, may, to the same extent as provided in subsections (a) through (b), intervene as a matter of right in any proceeding which relates to rates or rate design of nonregulated gas utilities.

Sec. 306. Gas Utility Rate Design Proposals.

(a) STUDY.--(1) the Secretary, in consultation with the Commission and, after affording an opportunity for consultation and comment by representatives of the State regulatory commissions, gas utilities, and gas consumers, shall study and report to Congress on gas utility rate design within 18 months after the date of the enactment of this Act. Such study shall address the effect (both separately and in combination) of the following factors upon the items listed in paragraph (2): incremental pricing; marginal cost pricing; end user gas consumption taxes; wellhead natural gas pricing policies; demand-commodity rate design; declining block rates; interruptible service; seasonal rate differentials; and end user rate schedules.

(2) The items referred to in paragraph (1) are as follows:

(A) natural gas pipeline and local distribution company load factors;

(B) rates to each class of user, including residential, commercial, and industrial users;

(C) the change in total costs resulting from gas utility designs (including capital and operating costs) to gas consumers or classes thereof;

(D) demand for, and consumption of, natural gas;

(E) end use profiles of natural gas pipelines and local distribution companies; and

(F) competition with alternative fuels.

(b) PROPOSALS.--Based upon the study prepared pursuant to subsection (a), the Secretary shall develop proposals to improve gas utility rate design and to encourage conservation of natural gas. Such proposals shall include any comments and recommendations of the Commission.

(c) TRANSMISSION TO CONGRESS.--The proposals prepared under subsection (b) shall be transmitted, together with any legislative recommendations, to each House of Congress not later than 6 months after the date of submission of the study under subsection (a). Such proposals shall be accompanied by an analyses of--

(1) the projected savings (if any) in consumption of natural gas, and other energy resources,

(2) changes (if any) in the cost of natural gas to consumers, which are likely to result from the implementation nationally of each of such proposals, and

(3) the effects of the proposals on other provisions of this Act on gas utility rate structures.

(d) PUBLIC PARTICIPATION.--The Secretary shall provide for public participation in the conduct of the study under subsection (a) and the preparation of proposals under subsection (b).

Sec. 307. Judicial Review and Enforcement.

(a) LIMITATION OF FEDERAL JURISDICTION.--(1) Notwithstanding any other provision of law, no court of the United States shall have jurisdiction over any action arising under any provision of this title except for--

(A) an action over which a court of the United States has jurisdiction under paragraph (2), or

(B) review in the Supreme Court of the United States in accordance with sections 1257 and 1258 of title 28 of the United States Code.

(2) The Secretary may bring an action in any appropriate court of the United States to enforce his right to intervene under section 305 and such court shall have jurisdiction to grant appropriate relief.

(b) ENFORCEMENT.--(1) Any person may bring an action to enforce the requirements of this title in the appropriate State court. Such action in a State court shall be pursuant to applicable State procedures.

(2) Nothing in this title shall authorize the Secretary to appeal or otherwise seek judicial review of the decisions of a State regulatory authority or nonregulated gas utility or to become a party to any action to obtain such review or appeal. The Secretary may participate as an amicus curiae in any judicial review of an action arising under the provisions of this title.

Sec. 308. Relationship to Other Applicable Law.

Nothing in this title prohibits any State regulatory authority or nonregulated gas utility from adopting, pursuant to State law, any standard or rule affecting gas utilities which is different from any standard established by this title.

Sec. 309. Reports Respecting Standards.

(a) STATE AUTHORITIES AND NONREGULATED UTILITIES.--Not later than 1 year after the date of the enactment of this Act and annually thereafter for 10 years, each State regulatory authority (with respect to each gas utility for which it has ratemaking authority), and each nonregulated gas utility, shall report to the Secretary, in such manner as the Secretary shall prescribe, respecting its consideration of the standards established by this title. Such report shall include a summary of the determinations made and actions taken with respect to each of such standards on a utility-by-utility basis.

(b) SECRETARY.--Not later than 18 months after the date of the enactment of this Act and annually thereafter for 10 years, the Secretary shall submit a report to the President and the Congress containing--

(1) a summary of the reports submitted under subsection (a),

(2) his analysis of such reports, and

(3) his actions under this title, and his recommendations for such further Federal actions, including any legislation, regarding retail gas utility rates (and other practices) as may be necessary to carry out the purposes of this title.

Sec. 310. Prior and Pending Proceedings.

For purposes of this title, proceedings commenced by any State regulatory authority (with respect to gas utilities for which it has rate-making authority) and any nonregulated gas utility before the date of the enactment of this Act and actions taken before such date in such proceedings shall be treated as complying with the requirements of this title if such proceedings and actions substantially conform to such requirements. For purposes of this title, any such proceeding or action commenced before the date of enactment of this Act but not completed before such date shall comply with the requirements of this title, to the maximum extent practicable, with respect to so much of such proceeding or action as takes place after such date.

Sec. 311. Relationship to Other Authority.

Nothing in this title shall be construed to limit or affect any authority of the Secretary or the Commission under any other provision of law.

TITLE IV--SMALL HYDROELECTRIC POWER PROJECTS

Sec. 401. Establishment of Program.

The Secretary shall establish a program in accordance with this title to encourage municipalities, electric cooperatives, industrial development agencies, nonprofit organizations, and other persons to undertake the development of small hydroelectric power projects in connection with existing dams which are not being used to generate electric power.

Sec. 402. Loans for Feasibility Studies.

(a) LOAN AUTHORITY.--The Secretary, after consultation with the Commission, is authorized to make a loan to any municipality, electric cooperative, industrial development agency, nonprofit organization, or other person to assist such person in defraying up to 90 percent of the costs of--

(1) studies to determine the feasibility of undertaking a small hydroelectric power project at an existing dam or dams and

(2) preparing any application for a necessary license or other Federal, State, and local approval respecting such a project at an existing dam or dams and of participating in any administrative proceeding regarding any such application.

(b) CANCELLATION.--The Secretary may cancel the unpaid balance and any accrued interest on any loan granted pursuant to this section if he determines on the basis of the study that the small hydroelectric power project would not be technically or economically feasible.

Sec. 403. Loans for Project Costs.

(a) AUTHORITY.--The Secretary is authorized to make loans to any municipality, electric cooperative, industrial development agency, nonprofit organization, or other person of up to 75 percent of the project costs of a small hydroelectric power project. No such loan may be made unless the Secretary finds that--

(1) the project will be constructed in connection with an existing dam or dams,

(2) all licenses and other required Federal, State, and local approvals necessary for construction of the project have been issued,

(3) the project will have no significant adverse environmental effects, including significant adverse effects on fish and wildlife, on recreational use of water, and on stream flow, and

(4) the project will not have a significant adverse effect on any other use of the water used by such project.

The Secretary may make a commitment to make a loan under this subsection to an applicant who has not met the requirements of paragraph (2), pending compliance by such applicant with such requirements. Such commitment shall be for [a] period of not to exceed 3 years unless the Secretary, in consultation with the Commission, extends such period for good cause shown. Notwithstanding any such commitment, no such loan shall be made before such person has complied with such requirements.

(b) PREFERENCE.--The Secretary shall give preference to applicants under this section who do not have available alternative financing which the Secretary deems appropriate to carry out the project and whose projects will provide useful information as to the technical and economic feasibility of--

(1) the generation of electric energy by such projects, and

(2) the use of energy produced by such projects.

(c) INFORMATION.--Every applicant for a license for a small hydroelectric power project receiving loans pursuant to this section shall furnish the Secretary with such information as the Secretary may require regarding equipment and services proposed to be used in the design, construction, and operation of such project. The Secretary shall have the right to forbid the use in such project of any equipment or services he finds inappropriate for such project by reason of cost, performance, or failure to carry out the purposes of this section. The Secretary shall make information which he obtains under this subsection available to the public, other than information described as entitled to confidentiality under section 11(d) of the Energy Supply and Environmental Coordination Act of 1974.

(d) JOINT PARTICIPATION.--In making loans for small hydroelectric power projects under this section, the Secretary shall encourage joint participation, to the extent permitted by law, by applicants eligible to receive loans under this section with respect to the same project.

Sec. 404. Loan Rates and Repayment.

(a) INTEREST.--Each loan made pursuant to this title shall bear interest at the discount or interest rate used at the time the loan is made for water resources planning projects under section 80 of the Water Resources Development Act of 1974 (42 U.S.C. 1962-17(a)). Each such loan shall be for such term, as the Secretary deems appropriate, but not in excess of--

(1) 10 years (in the case of a loan under section 402) or

(2) 30 (in the case of a loan under section 403).

(b) REPAYMENTS.--Amounts repaid on loans made pursuant to this title shall be deposited into the United States Treasury as miscellaneous receipts.

Sec. 405. Simplified and Expeditious Licensing Procedures.

(a) ESTABLISHMENT OF PROGRAM.--The Commission shall establish, in such manner as the Commission deems appropriate, consistent with the applicable provisions of law, a program to use simple and expeditious licensing procedures under the Federal Power Act for small hydroelectric power projects in connection with existing dams.

(b) PREREQUISITES.--Before issuing any license under the Federal Power Act for the construction or operation of any small hydroelectric power project the Commission--

(1) shall assess the safety of existing structures in any proposed project (including possible consequences associated with failure of such structures), and

(2) shall provide an opportunity for consultation with the Council on Environmental Quality and the Environmental Protection Agency with respect to the environmental effects of such project.

Nothing in this subsection exempts any such project from any requirement applicable to any such project under the National Environmental Policy Act of 1969, the Fish and Wildlife Coordination Act, the Endangered Species Act, or any other provision of Federal law.

(c) FISH AND WILDLIFE FACILITIES.--The Commission shall encourage applicants for licenses for small hydroelectric power projects to make use of public funds and other assistance for the design and construction of fish and wildlife facilities which may be required in connection with any development of such project.

(d) EXEMPTIONS FROM LICENSING REQUIREMENTS IN CERTAIN CASES.--The Commission may in its discretion (by rule or order) grant an exemption in whole or in part from the requirements (including the licensing requirements) of part I of the Federal Power Act to small hydroelectric power projects having a proposed installed capacity of 5,000 kilowatts or less, on a case-by-case basis or on the basis of classes or categories of projects, subject to the same limitations (to ensure protection for fish and wildlife as well as other environmental concerns) as those which are set forth in subsection (c) and (d) of section 30 of the Federal Power Act with respect to determinations made and exemptions granted under subsection (a) of such section 30: and subsection (c) and (d) of such section 30 shall apply with respect to actions taken and exemptions granted under this subsection. Except as specifically provided in this subsection, the granting of an exemption to a project under this subsection shall in no case have the effect of waiving or limiting the application (to such project) of the second sentence of subsection (b) of this section.

Sec. 406. New Impoundments.

Nothing in this title authorizes (1) the loan of funds for construction of any new dam or other impoundment, or (2) the simple and expeditious licensing of any such new dam or other impoundment.

Sec. 407. Authorizations.

There are hereby authorized to be appropriated for each of the fiscal years ending September 30, 1978, September 30, 1979, and September 30, 1980, not to exceed $10,000,000 for loans to be made pursuant to section 402, such funds to remain available until expended. There are hereby authorized to be appropriated for each of the fiscal years ending September 30, 1978, September 30, 1979, September 30, 1980, not to exceed $100,000,000 for loans to be made pursuant to section 403, such funds to remain available until expended.

Sec. 408. Definitions.

(a) For purposes of this title, the term--

(1) "small hydroelectric power project" means any hydroelectric power project which is located at the site of any existing dam, which uses the water power potential of such dam, and which has not more than 30,000 kilowatts of installed capacity;

(2) “electric cooperative” means any cooperative association eligible to receive loans under section 4 of the Rural Electrification Act of 1936 (7 U.S.C. 904);

(3) “industrial development agency” means any agency which is permitted to issue obligations the interest on which is excludable from gross income under section 103 of the Internal Revenue Code of 1954;

(4) “project costs” means the cost of acquisition or construction of all facilities and services and the cost of acquisition of all land and interests in land used in the design and construction and operation of a small hydroelectric power project;

(5) “nonprofit organization” means any organization described in section 501(c)(3) or 501(c)(4) of the Internal Revenue Code of 1954 and exempt from tax under section 501(a) of such Code (but only with respect to a trade or business carried on by such organization which is not an unrelated trade or business, determined by applying section 513(a) to such organization);

(6) “existing dam” means any dam, the construction of which was completed on or before ~~April 20, 1977~~July 22, 2005, and which does not require any construction or enlargement of impoundment structures (other than repairs or reconstruction) in connection with the installation of any small hydroelectric power project;

(7) “municipality” has the meaning provided in section 3 of the Federal Power Act; and

(8) “person” has the meaning provided in section 3 of the Federal Power Act.

(b) The requirement in subsection (a)(1) that a project be located at the site of an existing dam in order to qualify as a small hydroelectric power project, and the other provisions of this title which require that a project be at or in connection with an existing dam (or utilize the potential of such dam) in order to be assisted under or included within such provisions, shall not be construed to exclude--

(1) from the definition contained in such subsection (a)(1), or

(2) from any other provision of this title, any project which utilizes or proposes to utilize natural water features for the generation of electricity, without the need for any dam or impoundment, in a manner which (as determined by the Commission) will achieve the purposes of this title and will do so without any adverse effect upon such natural water features.

TITLE V--CRUDE OIL TRANSPORTATION SYSTEMS

Sec. 501. Findings.

The Congress finds and declares that--

(1) a serious crude oil supply shortage may soon exist in portions of the United States;

(2) a large surplus of crude oil on the west coast of the United States is projected;

(3) any substantial curtailment of Canadian crude oil exports to the United States could create a severe crude oil shortage in the northern tier States;

(4) pending the authorization and completion of west-to-east crude oil delivery systems, Alaskan crude oil in excess of west coast needs will be transshipped through the Panama Canal at a high transportation cost;

(5) national security and regional supply requirements may be such that west-to-east crude delivery systems serving both the northern tier States and inland States, consistent with the requirements of section 410 of the Act approved November 16, 1973 (87 Stat. 594), commonly known as the Trans-Alaska Pipeline Authorization Act, are needed;

(6) expeditious Federal and State decisions for west-to-east crude oil delivery systems are of the utmost priority; and

(7) resolution of the west coast crude oil surplus and the need for crude oil in northern tier States and inland States require the assignment and coordination of overall responsibility within the executive branch to permit expedited action on all necessary environmental assessments and decisions on permit applications concerning delivery systems.

Sec. 502. Statement of Purposes.

The purposes of this title are--

(1) to provide a means for--

(A) selecting delivery systems to transport Alaskan and other crude oil to northern tier States and inland States, and

(B) resolving both the west coast crude oil surplus and the crude oil supply problems in the northern tier States;

(2) to provide an expedited procedure for acting on applications for all Federal permits, licenses, and approvals required for the construction and operation or any transportation system approved under this title and the Long BeachMidland project; and

(3) to assure that Federal decisions with respect to crude oil transportation systems are coordinated with State decisions to the maximum extent practicable.

SEC. 503. DEFINITIONS.

As used in this title--

(1) The term "northern tier States" means the States of Washington, Oregon, Idaho, Montana, North Dakota, Minnesota, Michigan, Wisconsin, Illinois, Indiana, and Ohio.

(2) The term "inland States" means those States in the United States other than northern tier States and the States of California, Alaska, and Hawaii.

(3) The term "crude oil transportation system" means a crude oil delivery system (including the location of such system) for transporting Alaskan and other crude oil to northern tier States and inland States, but such term does not include the Long Beach-Midland project.

(4) The term "Long Beach-Midland project" means the crude oil delivery system which was the subject of, and is generally described in, the "Final Environmental Impact Statement, Crude Oil Transportation System: Valdez, Alaska, to Midland, Texas (as proposed by Sohio Transportation Company)" , the availability of which was announced by the Department of the Interior in the Federal Register on June 1, 1977 (42 Fed. Reg. 28008).

(5) The term "Federal agency" means an Executive agency, as defined in section 105 of title 5, United States Code.

SEC. 504. APPLICATIONS FOR APPROVAL OF PROPOSED CRUDE OIL TRANSPORTATION SYSTEMS.

The following applications for construction and operation of a crude oil transportation system submitted to the Secretary of the Interior by an applicant are eligible for consideration under this title:

(1) Applications received by the Secretary before the 30th day after the date of the enactment of this Act.

(2) Applications received by the Secretary during the 60-day period beginning on the 30th day after the date of the enactment of this Act, if the Secretary determines that consideration and review of the proposal contained in such application is in the national interest and that such consideration and review could be completed within the time limits established under this title.

An application under this section may be accepted by the Secretary only if it contains a general description of the route of the proposed system and identification of the applicant and any other person who, at the time of filing, has a financial or other interest in the system or is a party to an agreement under which such person would acquire a financial or other interest in the system.

SEC. 505. REVIEW SCHEDULE.

(a) ESTABLISHMENT.--The Secretary of the Interior, after consultation with the heads of appropriate Federal agencies, shall establish an expedited schedule for conducting reviews and making recommendations concerning crude oil transportation systems proposed in applications filed under section 504 and for obtaining information necessary for environmental impact statements required under section 102 of the National Environmental Policy Act of 1969 (42 U.S.C. 4332) with respect to such proposed systems.

(b) ADDITIONAL INFORMATION.--(1) On his own initiative or at the request of the head of any Federal agency covered by the review schedule established under subsection (a), the Secretary of the Interior shall require that an applicant provide such additional information as may be necessary to conduct the review of the applicant's proposal. Such information may include--

(A) specific details of the route (and alternative routes) and identification of Federal lands affected by any such route;

(B) information necessary for environmental impact statements; and

(C) information necessary for the President's determination under section 507(a).

(2) If, within a reasonable time, an applicant does not--

(A) provide information required under this subsection, or

(B) comply with any requirement of section 304 of the Federal Land Policy and Management Act of 1976 (90 Stat. 2765; 43 U.S.C. 1734),

the Secretary of the Interior may declare the application ineligible for consideration under this title. After making such a declaration, the Secretary of the Interior shall notify the applicant and the President of such ineligibility.

(c) RECOMMENDATIONS OF THE HEADS OF FEDERAL AGENCIES.--(1) Pursuant to the schedule established under subsection (a), heads of Federal agencies covered by such schedule shall conduct a review of a proposed crude oil transportation system eligible for consideration under this title and shall submit their recommendations concerning such systems (and the basis for such recommendations) to the Secretary of the Interior for submission to the President. After receipt of such recommendations and before their submission to the President, the Secretary of the Interior shall provide an opportunity for comments in accordance with paragraph (2). The Secretary of the Interior shall forward such comments to the President with the recommendations--

(A) in the case of applications filed under section 504(1), on or before December 1, 1978, and

(B) in the case of applications filed under section 504(2), on or before the 60th day after December 1, 1978.

(2)(A) After receipt of recommendations under paragraph (1) the Secretary of the Interior shall provide appropriate means by which the Governor and any other official of any State and any official of any political subdivision of a State, may submit written comments concerning proposed crude oil transportation systems eligible for consideration under this title.

(B) After receipt of recommendations referred to in subparagraph (A), the Secretary of the Interior shall make such comments and recommendations available to the public and provide an opportunity for submission of written comments.

(d) REVIEW BY THE FEDERAL TRADE COMMISSION; EFFECT ON THE ANTITRUST LAWS.--(1) Promptly after he receives an application for a proposed crude oil transportation system eligible for consideration under this title, the Secretary of the Interior shall submit to the Federal Trade Commission a copy of such application and such other information as the Commission may reasonably require. The Commission may prepare and submit to the President a report on the impact of implementation of such application upon competition and restraint of trade and on whether such implementation would be inconsistent with the antitrust laws. Such report shall be made available to the public. Nothing in this subsection shall be construed to prevent the President from making his decision under section 507(a) in the absence of such report.

(2) Nothing in this title shall bar the Attorney General or any other appropriate officer or agent of the United States from challenging any anticompetitive act or practice related to the ownership, construction, or operation of any crude oil transportation system approved under this title. The approval of any such system under this title shall not be deemed to convey to any person immunity from civil or criminal liability or to create defenses to actions under the antitrust laws and shall not modify or abridge any private right of action under such laws.

(e) FILING AND REVIEW OF PERMITS, RIGHTS-OF-WAY APPLICATIONS, ETC., NOT AFFECTED.--Nothing in this title shall be construed to prevent the acceptance and review by any Federal agency of any application for any Federal permit, right-of-way, or other authorizations under other provisions of law for a crude oil transportation system eligible for consideration under this title; except that any determination with respect to such an application may be made only in accordance with the provisions of section 509(a).

SEC. 506. ENVIRONMENTAL IMPACT STATEMENTS.

(a) PREPARATION OF ENVIRONMENTAL IMPACT STATEMENTS.--Any Federal agency required under section 102 of the National Environmental Policy Act of 1969 (42 U.S.C. 4332) to issue an environmental impact statement concerning a proposed crude oil transportation system eligible for consideration under this title shall, in preparing such statement, utilize, to the maximum extent practicable and consistent with such Act, appropriate data, analyses, conclusions, findings, and decisions regarding environmental impacts developed or made by any other Federal or State agency.

(b) FILING OF ENVIRONMENTAL IMPACT STATEMENTS.--On or before December 1, 1978, all environmental impact statements concerning proposed crude oil transportation systems eligible for consideration under this title and required under section 102 of the National Environmental Policy Act of 1969 shall be completed, made available for public review and comment, revised to the extent appropriate in light of such comment, and submitted to the President and the Council on Environmental Quality; except that in the case of any environmental impact statement concerning any crude oil transportation system which is eligible for consideration and which was filed under section 504(2) of this title, such actions may be taken not later than 60 days after December 1, 1978.

(c) REPORT OF THE COUNCIL ON ENVIRONMENTAL QUALITY.--Promptly after receiving an environmental impact statement referred to in subsection (b) for a crude oil transportation system, the Council on Environmental Quality shall submit to the President a report on the Council's opinion concerning such statement and concerning other matters related to the environmental impact of such system.

SEC. 507. DECISION OF THE PRESIDENT.

(a) DECISION CONCERNING APPROVAL OR DISAPPROVAL OF PROPOSED SYSTEMS.--(1) After reviewing all the information submitted to him concerning the various proposed crude oil transportation systems eligible for consideration under this title (including environmental impact statements, comments, reports, recommendations, and other information submitted to him at any time before he makes his decision) and after consulting the Secretaries of Energy, the Interior, and Transportation, the President shall decide which, if any, of such systems shall be approved for the purposes of section 508 (relating to procedures for waiver of law), section 509 (relating to expedited procedures for issuance of permits), section 510 (relating to negotiations with the Government of Canada), and section 511 (relating to judicial review). A decision approving a crude oil transportation system may include such modifications and alterations in such system as the President finds appropriate. The President shall issue his decision within 45 days after receiving recommendations and comments submitted to him under section 505(c), except that the President, for such period as he deems necessary, but not to exceed 60 days, may delay his decision and its issuance if he determines that additional time is otherwise necessary to enable him to make a decision. If the President so delays his decision, he shall promptly notify the House of Representatives and the Senate of such delay and shall submit a full explanation of the basis for such delay.

(2) Any decision made under this subsection approving a system proposed under this title shall include a determination that construction and operation of such system is in the national interest and shall be based upon the criteria specified in subsection (b).

(b) CRITERIA.--(1) The criteria for making a decision under this subsection shall include findings of--

(A) environmental impacts of the proposed systems and the capability of such systems to minimize environmental risks resulting from transportation of crude oil;

(B) the amount of crude oil available to northern tier States and inland States and the projected demand in those States under each of such systems;

(C) transportation costs and delivered prices of crude oil by region under each of such systems;

(D) construction schedules for each of such systems and possibilities for delay in such schedules;

(E) feasibility of financing for each of such systems;

(F) capital and operating costs of each of such systems, including an analysis of the reliability of cost estimates and the risk of cost overruns;

(G) net national economic costs and benefits of each such system;

(H) the extent to which each system complies with the provisions of section 410 of the Act approved November 16, 1973 (87 Stat. 594), commonly known as the Trans-Alaska Pipeline Authorization Act;

(I) the effect of each such system on international relations, including the status and time schedule for any necessary Canadian approvals and plans;

(J) impact upon competition by each system;

(K) degree of safety and efficiency of design and operation of each system;

(L) potential for interruption of deliveries of crude oil from the west coast under each such system;

(M) capacity and cost of expanding such system to transport additional volumes of crude oil in excess of initial system capacity;

(N) national security considerations under each such system;

(O) relationship of each such system to national energy policy; and

(P) such other factors as the President deems appropriate.

(2) The period of time for which such findings shall be made shall be the useful life of the crude oil transportation system involved.

(c) PUBLICATION OF FINDINGS AND DECISION.--The President shall make available to the public at the time of issuance of a decision under this section a written statement setting forth findings with respect to each of the criteria specified in subsection (b) and describing the nature and route of crude oil transportation systems, if any, which are approved in the decision. If the President's decision is to approve a system, each statement shall set forth his reasons for approving such system over other proposed systems (if any) eligible for consideration under this title. Such statement along with notification of such decision shall be published in the Federal Register.

SEC. 508. PROCEDURES FOR WAIVER OF FEDERAL LAW.

(a) WAIVER OF PROVISIONS OF FEDERAL LAW.--The President may identify those provisions of Federal law (including any law or laws regarding the location of a crude oil transportation system but not including any provision of the antitrust laws) which, in the national interest, as determined by the President, should be waived in whole or in part to facilitate construction or operation of any such system approved under section 507 or of the Long Beach-Midland project, and he shall submit any such proposed waiver to both Houses of the Congress. The provisions so identified shall be waived with respect to actions to be taken to construct or operate such system or project only upon enactment of a joint resolution within the first period of 60 calendar days of continuous session of Congress beginning on the date of receipt by the House of Representatives and the Senate of such proposal.

(b) JOINT RESOLUTION.--The resolving clause of the joint resolution referred to in subsection (a) is as follows: "That the House of Representatives and Senate approve the waiver of the provisions of law (_____________) as proposed by the President, submitted to the Congress on _________________ 19 ." . The first blank space therein being filled with the citation to the provisions of law proposed to be waived by the President and the second blank space therein being filled with the date on which the President submits his decision to wave such provisions of law to the House of Representatives and the Senate. Rules and procedures for consideration of any such joint resolution shall be governed by section 8 (c) and (d) of the Alaskan Natural Gas Transportation Act, other than paragraph (2) of section 8(d), except that for the purposes of this subsection, the phrase "a waiver of provisions of law" shall be substituted in section 8(d) each place where the phrase "an Alaska natural gas transportation system" appears.

SEC. 509. EXPEDITED PROCEDURES FOR ISSUANCE OF PERMITS: ENFORCEMENT OF RIGHTS-OF-WAY.

(a) EXPEDITED PROCEDURES FOR APPROVED SYSTEMS.--After issuance of a decision by the President approving any crude oil transportation system, all Federal officers and agencies shall expedite, to the maximum extent practicable, consistent with applicable provisions of law, all actions necessary to determine whether to issue, administer, or enforce rights-of-way across Federal lands and to issue Federal permits in connection with, or otherwise to authorize, construction and operation of such system. Any such action shall be consistent with applicable provisions of law. After taking any such action, such officer or agency shall publish notification of the taking of such action in the Federal Register.

(b) EXPEDITED PROCEDURES FOR LONG BEACH-MIDLAND PROJECT.--All decisions regarding issuance of Federal permits, rights-of-way, and leases and other Federal authorizations necessary for construction and operation of the Long Beach-Midland project shall be consistent with applicable provisions of Federal law, except that such decisions shall be made within 30 days after the date this title becomes effective. The President may extend the date by which such decisions, under the preceding sentence, are to be made to a date not later than 90 days after the effective date of this title. Notification of the making of such decisions shall be published in the Federal Register. Nothing in this section affects any decision made before the date of the enactment of this title.

(c) LAW GOVERNING RIGHTS-OF-WAY.--Rights-of-way over any Federal land with respect to an approved crude oil transportation system or the Long Beach-Midland project shall be governed by the provisions of section 28 of the Act of February 25, 1920, commonly referred to as the Mineral Leasing Act of 1920 (30 U.S.C. 185), other than subsection (w)(2) of such section.

Sec. 510. Negotiations with the Government of Canada.

With respect to any crude oil transportation system approved under section 507(a) all or any part of which is to be located in Canada, the President of the United States is authorized and requested to enter into negotiations with the Government of Canada to determine what measures can be taken to expedite the granting of approvals by the Government of Canada for construction or operation of such system, and he is authorized and requested to explore the possibility of further exchanges of crude oil supplies between the United States and Canada.

Sec. 511. Judicial Review.

(a) NOTICE.--The President or any other Federal officer shall cause notice to be published in the Federal Register and in newspapers of general circulation in the areas affected whenever he makes any decision described in subsection (b).

(b) REVIEW OF CERTAIN FEDERAL ACTIONS.--Any action seeking judicial review of an action or decision of the President or any other Federal officer taken or made after the date of the enactment of this Act concerning the approval or disapproval of a crude oil transportation system or the issuance of necessary rights-of-way, permits, leases, and other authorizations for the construction, operation, and maintenance of the Long Beach-Midland project or a crude oil transportation system approved under section 507(a) may only be brought within 60 days after the date on which notification of the action or decision of such officer is published in the Federal Register, or in newspapers of general circulation in the areas affected, whichever is later.

(c) JURISDICTION OF COURTS.--An action under subsection (b) shall be barred unless a petition is filed within the time specified. Any such petition shall be filed in the appropriate United States district court. A copy of such petition shall be transmitted by the clerk of such court to the Secretary. Notwithstanding the amount in controversy, such court shall have jurisdiction to determine such proceeding in accordance with the procedures hereinafter provided and to provide appropriate relief. No State or local court shall have jurisdiction of any such claim whether in a proceeding instituted before, on, or after the date this title becomes effective. No court shall have jurisdiction to grant any injunctive relief against the issuance of any right-of-way, permit, lease, or other authorization in connection with a crude oil transportation system approved under section 507(a) or the Long Beach-Midland project, except as part of a final judgment entered in a case involving a claim filed pursuant to this section.

.01 Section 511(c), appearing in P.L. 95-617, November 9, 1978, was amended in P.L. 98-620, November 8, 1984, by deleting the sentence "Any such proceeding shall be assigned for hearing at the earliest possible date and shall be expedited by such court," following the sentence ending ". . . or after the date this title becomes effective."

Sec. 512. Authorization for Appropriation.

There are authorized to be appropriated to the Secretary of the Interior to carry out his responsibilities under this title not to exceed $500,000 for the fiscal year ending on September 30, 1978, and not to exceed $1,000,000 for the fiscal year ending on September 30, 1979.

TITLE VI--MISCELLANEOUS PROVISIONS

Sec. 601. Study Concerning Electric Rates of State Utility Agencies.

(a) STUDY AND REPORT.--The Secretary, in consultation with the Commission and appropriate State regulatory authorities and other persons, shall conduct a study concerning the effects of provisions of Federal law on rate[s] established by State utility agencies. The Secretary shall submit a report to Congress containing the results of such study not later than 1 year after the date of the enactment of this Act.

(b) DEFINITION.--The term "State utility agency" means an agency of a State (not including any political subdivision or agency thereof or any public power district) which is an electric utility.

Sec. 602. Seasonal Diversity Electricity Exchange.

(a) AUTHORITY.--The Secretary may acquire rights-of-way by purchase, including eminent domain, through North Dakota, South Dakota, and Nebraska for transmission facilities for the seasonal diversity exchange of electric power to and from Canada if he determines--

(1) after opportunity for public hearing--

(A) that the exchange is in the public interest and would further the purposes referred to in section 101 (1) and (2) of this Act and that the acquisition of such rights-of-way and the construction and operation of such transmission facilities for such purposes is otherwise in the public interest,

(B) that a permit has been issued in accordance with subsection (b) for such construction, operation, maintenance, and connection of the facilities at the border for the transmission of electric energy between the United States and Canada as is necessary for such exchange of electric power, and

(C) that each affected State has approved the portion of the transmission route located in each State in accordance with applicable State law, or if there is no such applicable State law in such State, the Governor has approved such portion, and

(2) after consultation with the Secretary of the Interior and the heads of other affected Federal agencies, that the Secretary of the Interior and the heads of such other agencies concur in writing in the location of such portion of the transmission facilities as crosses Federal land under the jurisdiction of such Secretary or such other Federal agency, as the case may be.

The Secretary shall provide to any State such cooperation and technical assistance as the State may request and as he determines appropriate in the selection of a transmission route. If the transmission route approved by any State does not appear to be feasible and in the public interest, the Secretary shall encourage such State to review such route and to develop a route that is feasible and in the public interest. Any exercise by the Secretary of the power of eminent domain under this section shall be in accordance with other applicable provisions of Federal law. The Secretary shall provide public notice of his intention to acquire any right-of-way before exercising such power of eminent domain with respect to such right-of-way.

(b) PERMIT.--Notwithstanding any transfer of functions under the first sentence of section 301(b) of the Department of Energy Organization Act, no permit referred to in subsection (a)(1)(B) may be issued unless the Commission has conducted hearings and made the findings required under section 202(e) of the Federal Power Act and under the applicable execution order respecting the construction, operation, maintenance, or connection at the borders of the United States of facilities for the transmission of electric energy between the United States and a foreign country. Any finding of the Commission under an applicable executive order referred to in this subsection shall be treated for purposes of judicial review as an order issued under section 202(e) of the Federal Power Act.

(c) TIMELY ACQUISITION BY OTHER MEANS.--The Secretary may not acquire any rights-of-way under this section unless he determines that the holder or holders of a permit referred to in subsection (a)(1)(B) are unable to acquire such rights-of-way under State condemnation authority, or after reasonable opportunity for negotiation, without unreasonably delaying construction, taking into consideration the impact of such delay on completion of the facilities in a timely fashion.

(d) PAYMENTS BY PERMITTEES.--(1) The property interest acquired by the Secretary under this section (whether by eminent domain or other purchase) shall be transferred by the Secretary to the holder of a permit referred to in subsection (b) if such holder has made payment to the Secretary of the entire costs of the acquisition of such property interest, including administrative costs. The Secretary may accept, and expend, for purposes of such acquisition, amounts from any such person before acquiring a property interest to be transferred to such person under this section.

(2) If no payment is made by a permit holder under paragraph (1), within a reasonable time, the Secretary shall offer such rights-of-way to the original owner for reacquisition at the original price paid by the Secretary. If such original owner refuses to reacquire such property after a reasonable period, the Secretary shall dispose of such property in accordance with applicable provisions of law governing disposal of property of the United States.

(e) FEDERAL LAW GOVERNING FEDERAL LANDS.--This section shall not affect any Federal law governing Federal lands.

(f) REPORTS.--The Secretary shall report annually to the Congress on the actions, if any, taken pursuant to this section.

Sec. 603. Utility Regulatory Institute.

(a) MATCHING GRANTS.--The Secretary may make grants under this section to an institute established by the National Association of Regulatory Utility Commissioners to enable such institute to--

(1) conduct research on electric and gas utility regulatory policy issues,

(2) develop data processing and retrieval methods for electric and gas utility ratemaking, and

(3) perform other functions directly related to assisting State regulatory authorities in carrying out their functions under State law and this Act.

(b) FEDERAL SHARE.--Grants under this section shall not be used to provide more than the following percentages of the cost to the institute of carrying out the activities specified in subsection (a):

(1) 80 percent for the fiscal year 1979; and

(2) 60 percent for the fiscal year 1980.

The remaining amounts expended by the institute may not be provided from Federal sources.

(c) RESTRICTIONS.--Grants under this section may not be made subject to terms and conditions other than those the Secretary deems necessary for purposes of administering this section and for purposes of assuring that--

(1) all information gathered by the institute is available to the Secretary, the Commission, and the public, and

(2) no portion of any such grant is used to support or oppose any legislative proposal except by means of testimony by representatives of the institute provided by invitation to a committee of Congress or of a State legislature.

(d) AUTHORIZATION OF APPROPRIATIONS.--There is authorized to be appropriated not more than $2,000,000 for each of the fiscal years 1979 and 1980 for purposes of making grants under this section. No amounts may be appropriated for any fiscal year after the fiscal year 1980 to carry out the purposes of this section without a specific authorization of Congress.

Note: Section 604 amended Sections 801 and 806 of the Surface Mining Control and Reclamation Act of 1977. Not reproduced.

Sec. 605. Conserved Natural Gas.

(a) GENERAL RULE.--(1) For purposes of determining the natural gas entitlement of any local distribution company under any curtailment plan, if the Commission revises any base period established under such plan, the volumes of natural gas which such local distribution company demonstrates--

(A) were sold by the local distribution company, for a priority use immediately before the implementation of conservation measures, and

(B) were conserved by reason of the implementation of such conservation measures,

shall be treated by the Commission following such revision as continuing to be used for the priority use referred to in subparagraph (A).

(2) The Commission shall, by rule, prescribe methods for measurement of volumes of natural gas to which subparagraphs (A) and (B) of paragraph (1) apply.

(b) CONDITIONS, LIMITATIONS, ETC.--Subsection (a) shall not limit or otherwise affect any provision of any curtailment plan, or any other provision of law or regulation, under which natural gas may be diverted or allocated to respond to emergency situations or to protect public health, safety, and welfare.

(c) DEFINITIONS.--For purposes of this section--

(1) The term "conservation measures" means such energy conservation measures, as determined by the Commission, as were implemented after the base period established under the curtailment plan in effect on the date of the enactment of this Act.

(2) The term "local distribution company" means any person engaged in the transportation, or local distribution, of natural gas and the sale of natural gas for ultimate consumption.

(3) The term "curtailment plan" means a plan (including any modification of such plan required by the Natural Gas Policy Act of 1978) in effect under the Natural Gas Act which provides for recognizing and implementing priorities of service during periods of curtailed deliveries.

Sec. 606. Voluntary Conversion of Natural Gas Users to Heavy Fuel Oil.

(a) IN GENERAL.--(1) In order to facilitate voluntary conversion of facilities from the use of natural gas to the use of heavy petroleum fuel oil, the Commission shall, by rule, provide a procedure for the approval by the Commission of any transfer to any person described in paragraph 2 (B)(i), (ii), or (iii) of contractual interests involving the receipt of natural gas described in paragraph 2 (A).

(2)(A) The rule required under paragraph (1) shall apply to--

(i) natural gas--

(I) received by the user pursuant to a contract entered into before September 1, 1977, not including any renewal or extension thereof entered into on or after such date other than any such extension or renewal pursuant to the exercise by such user of an option to extend or renew such contract;

(II) other than natural gas the sale for resale or the transportation of which was subject to the jurisdiction of the Federal Power Commission under the Natural Gas Act as of September 1, 1977;

(III) which was used as a fuel in any facility in existence on September 1, 1977.

(ii) natural gas subject to a prohibition order issued under section 607.

(B) The rule required under paragraph (1) shall permit the transfer of contractual interests--

(i) to any interstate pipeline;

(ii) to any local distribution company served by an interstate pipeline; and

(iii) to any person served by an interstate pipeline for a high priority use by such person.

(3) The rule required under paragraph (1) shall provide that any transfer of contractual interests pursuant to such rule shall be under such terms and conditions as the Commission may prescribe. Such rule shall include a requirement for refund of any consideration, received by the person transferring contractual interests pursuant to such rule, to the extent such consideration exceeds the amount by which the costs actually incurred, during the remainder of the period of the contract with respect to which such contractual interests are transferred, in direct association with the use of heavy petroleum fuel oil as a fuel in the applicable facility exceeds the price under such contract for natural gas, subject to such contract, delivered during such period.

(4) In prescribing the rule required under paragraph (1), and in determining whether to approve any transfer of contractual interests, the Commission shall consider whether such

transfer of contractual interests is likely to increase demand for imported refined petroleum products.

(b) COMMISSION APPROVAL.--(1) No transfer of contractual interests authorized by the rule required under subsection (a)(1) may take effect unless the Commission issues a certificate of public convenience and necessity for such transfer if such natural gas is to be resold by the person to whom such contractual interests are to be transferred. Such certificate shall be issued by the Commission in accordance with the requirements of this subsection and those of section 7 of the Natural Gas Act, and the provisions of such Act applicable to the determination of satisfaction of the public convenience and necessity requirements of such section.

(2) The rule required under subsection (a)(1) shall set forth guidelines for the application on a regional or national basis (as the Commission determines appropriate) of the criteria specified in subsection (e)(2) and (3) to determine the maximum consideration permitted as just compensation under this section.

(c) RESTRICTIONS ON TRANSFERS UNENFORCEABLE.--Any provision of any contract, which provision prohibits any transfer of any contractual interests thereunder, or any commingling or transportation of natural gas subject to such contract with natural gas the sale for resale or transportation of which is subject to the jurisdiction of the Commission under the Natural Gas Act, or terminates such contract on the basis of any such transfer, commingling, or transportation, shall be unenforceable in any court of the United States and in any court of any State if applied with respect to any transfer approved under the rule required under subsection (a)(1).

(d) CONTRACTUAL OBLIGATIONS UNAFFECTED.--The person acquiring contractual interests transferred pursuant to the rule required under subsection (a)(1) shall assume the contractual obligations which the person transferring such contractual interests has under such contract. This section shall not relieve the person transferring such contractual interests from any contractual obligation of such person under such contract if such obligation is not performed by the person acquiring such contractual interests.

(e) DEFINITIONS.--For purposes of this section--

(1) The term “natural gas” has the same meaning as provided by section 2(5) of the Natural Gas Act.

(2) The term “just compensation”, when used with respect to any contractual interests pursuant to the rule required under subsection (a)(1), means the maximum amount of, or method of determining, consideration which does not exceed the amount by which--

(A) the reasonable costs (not including capital costs) incurred, during the remainder of the period of the contract with respect to which contractual interests are transferred pursuant to the rule required under subsection (a)(1), in direct association with the use of heavy petroleum fuel oil as a fuel in the applicable facility, exceeds

(B) the price under such contract for natural gas, subject to such contract, delivered during such period.

For purposes of subparagraph (A), the reasonable costs directly associated with the use of heavy petroleum fuel oil as a fuel shall include an allowance for the amortization, over the remaining useful life, of the undepreciated value of depreciable assets located on the premises containing such facility, which assets were directly associated with the use of natural gas and are not usable in connection with the use of such heavy petroleum fuel oil.

(3) The term “just compensation”, when used with respect to any intrastate pipeline which would have transported or distributed natural gas with respect to which contractual interests are transferred pursuant to the rule required under subsection (a)(1), means an amount equal to any loss of revenue, during the remaining period of the contract with respect to which contractual interests are transferred pursuant to the rule required under subsection (a)(1), to the extent such loss--

(A) is directly incurred by reason of the discontinuation of the transportation or distribution of natural gas resulting from the transfer of contractual interests pursuant to the rule required under subsection (a)(1); and

(B) is not offset by--

(i) a reduction in expenses associated with such discontinuation; and

(ii) revenues derived from other transportation or distribution which would not have occurred if such contractual interests had not been transferred.

(4) The term “contractual interests” means the right to receive natural gas under contract as affected by an applicable curtailment plan filed with the Commission or the appropriate State regulatory authority.

(5) The term “interstate pipeline” means any person engaged in natural gas transportation subject to the jurisdiction of the Commission under the Natural Gas Act.

(6) The term “high-priority use” means any use of natural gas (other than its use for the generation of steam for industrial purposes or electricity) identified by the Commission as a high priority use for which the Commission determines a substitute fuel is not reasonably available.

(7) The term “heavy petroleum fuel oil” means number 4, 5, or 6 fuel oil which is domestically refined.

(8) The term "local distribution company" means any person, other than any intrastate pipeline or any interstate pipeline, engaged in the transportation, or local distribution, of natural gas and the sale of natural gas for ultimate consumption.

(9) The term "intrastate pipeline" means any person engaged in natural gas transportation (not including gathering) which is not subject to the jurisdiction of the Commission under the Natural Gas Act.

(10) The term "facility" means any electric powerplant, or major fuel burning installation, as such terms are defined in the Powerplant and Industrial Fuel Use Act of 1978.

(11) The term "curtailment plan" means a plan (including any modification of such plan required by the Natural Gas Policy Act of 1978), in effect under the Natural Gas Act or State law, which provides for recognizing and implementing priorities of service during periods of curtailed deliveries by any local distribution company, intrastate pipeline, or interstate pipeline.

(12) The term "interstate commerce" has the same meaning as such term has under the Natural Gas Act.

(f) COORDINATION WITH THE NATURAL GAS ACT.--(1) Consideration in any transfer of contractual interests pursuant to the rule required under subsection (a)(1) of this section shall be deemed just and reasonable for purposes of sections 4 and 5 of the Natural Gas Act if such consideration does not exceed just compensation.

(2) No person shall be subject to the jurisdiction of the Commission under the Natural Gas Act as a natural gas-company (within the meaning of such Act) or to regulation as a common carrier under any provision of Federal or State law solely by reason of making any sale, or engaging in any transportation, of natural gas with respect to which contractual interests are transferred pursuant to the rule required under subsection (a)(1).

(3) Nothing in this section shall exempt from the jurisdiction of the Commission under the Natural Gas Act any transportation in interstate commerce of natural gas, any sale in interstate commerce for resale of natural gas, or any person engaged in such transportation or such sale to the extent such transportation, sale, or person is subject to the jurisdiction of the Commission under such Act without regard to the transfer of contractual interest pursuant to the rule required under subsection (a)(1).

(4) Nothing in this section shall exempt any person from any obligation to obtain a certificate of public convenience and necessity for the sale in interstate commerce for resale or the transportation in interstate commerce of natural gas with respect to which contractual interests are transferred pursuant to the rule required under subsection (a)(1).

(g) VOLUME LIMITATION.--No supplier of natural gas under any contract, with respect to which contractual interests have been transferred pursuant to the rule required under subsection (a)(1), shall be required to supply natural gas during any relevant period in volume amounts which exceed the lesser of--

(1) the volume determined by reference to the maximum delivery obligations specified in such contract;

(2) the volume which such supplier would have been required to supply, under the curtailment plan in effect for such supplier, to the person, who transferred contractual interests pursuant to the rule required under subsection (a)(1), if no such transfer had occurred; and

(3) the volume actually delivered or for which payment would have been made pursuant to such contract during the 12-calendar-month period ending immediately before such transfer of contractual interests.

Sec. 607. Emergency Conversion of Utilities and Other Facilities.

(a) PRESIDENTIAL DECLARATION.--The President may declare a natural gas supply emergency (or extend a previously declared emergency) if he finds that--

(1) a severe natural gas shortage, endangering the supply of natural gas for high-priority uses, exists or is imminent in the United States or in any region thereof; and

(2) the exercise of authorities under this section is reasonably necessary, having exhausted other alternative (not including section 303 of the Natural Gas Policy Act of 1978) to the maximum extent practicable, to assist in meeting natural gas requirements for such high-priority uses.

(b) LIMITATION.--(1) Any declaration of a natural gas supply emergency (or extension thereof) under subsection (a), shall terminate at the earlier of--

(A) the date on which the President finds that any shortage described in subsection (a) does not exist or is not imminent; or

(B) 120 days after the date of such declaration of emergency (or extension thereof).

(2) Nothing in this subsection shall prohibit the President from extending, under subsection (a), any emergency (or extension thereof) previously declared under subsection (a), upon the expiration of such declaration of emergency (or extension thereof) under paragraph (1)(B).

(c) PROHIBITIONS.--During a natural gas emergency declared under this section, the President may, by order, prohibit the burning of natural gas by any electric powerplant or major fuel-burning installation if the President determines that--

(1) such powerplant or installation had on September 1, 1977 (or at any time thereafter) the capability to burn petroleum products without damage to its facilities or equipment and without interference with operational requirements;

(2) significant quantities of natural gas which would otherwise be burned by such powerplant or installation could be made available before the termination of such emergency to any person served by an interstate pipeline for use by such person in a high-priority use; and

(3) petroleum products will be available for use by such powerplant or installation throughout the period the order is in effect.

(d) LIMITATIONS.--The President may specify in any order issued under this section the periods of time during which such order will be in effect and the quantity (or rate of use) of natural gas that may be burned by an electric powerplant or major fuel-burning installation during such period, including the burning of natural gas by an electric powerplant to meet peak load requirements. No such order may continue in effect after the termination or expiration of such natural gas supply emergency.

(e) EXEMPTION FOR SECONDARY USES.--The President shall exempt from any order issued under this section the burning of natural gas for the necessary processes of ignition, startup, testing, and flame stabilization by an electric powerplant or major fuel-burning installation.

(f) EXEMPTION FOR AIR-QUALITY EMERGENCIES.--The President shall exempt any electric powerplant or major fuel-burning installation in whole or in part, from any order issued under this section for such period and to such extent as the President determines necessary to alleviate any imminent and substantial endangerment to the health of persons within the meaning of section 303 of the Clean Air Act.

(g) LIMITATION ON INJUNCTIVE RELIEF.--(1) Except as provided in paragraph (2), no court shall have jurisdiction to grant any injunctive relief to stay or defer the implementation of any order issued under this section unless such relief is in connection with a final judgment entered with respect to such order.

(2)(A) On the petition of any person aggrieved by an order issued under this section, the United States District Court for the District of Columbia may, after an opportunity for a hearing before such court and on an appropriate showing, issue a preliminary injunction temporarily enjoining, in whole or in part, the implementation of such order.

(B) For purposes of this paragraph, subpenas for witnesses who are required to attend the District Court for the District of Columbia may be served in any judicial district of the United States, except that no writ of subpena under the authority of this section shall issue for witnesses outside of the District of Columbia at a greater distance than 100 miles from the place of holding court unless the permission of the District Court for the District of Columbia has been granted after proper application and cause shown.

(h) DEFINITIONS.--For purposes of this section--

(1) The terms “electric powerplant”, “powerplant”, “major fuel-burning installation”, and “installation” shall have the same meanings as such terms have under section 103 of the Powerplant and Industrial Fuel Use Act of 1978.

(2) The term “petroleum products” means crude oil, or any product derived from crude oil other than propane.

(3) The term “high priority use” means any--

(A) use of natural gas in a residence;

(B) use of natural gas in a commercial establishment in amounts less than 50 Mcf on a peak day; or

(C) any use of natural gas the curtailment of which the President determines would endanger life, health, or maintenance of physical property.

(4) The term “Mcf”, when used with respect to natural gas, means 1,000 cubic feet of natural gas measured at a pressure of 14.73 pounds per square inch (absolute) and a temperature of 60 degrees Fahrenheit.

(i) USE OF CERTAIN TERMS.--In applying the provisions of this section in the case of natural gas subject to a prohibition order issued under this section, the term “petroleum products” (as defined in subsection (h)(2) of this section) shall be substituted for the term “heavy petroleum fuel oil” (as defined in section 606(e)(7)) if the person subject to any order under this section demonstrates to the Commission that the acquisition and use of heavy petroleum fuel oil is not technically or economically feasible.

Note: Section 608 amended Section 7 of the Natural Gas Act. See ¶3207 .

SEC. 609. RURAL AND REMOTE COMMUNITIES ELECTRIFICATION GRANTS.

(a) Definitions- In this section:

(1) The term `eligible grantee' means a local government or municipality, peoples' utility district, irrigation district, and cooperative, nonprofit, or limited-dividend association in a rural area.

(2) The term `incremental hydropower' means additional generation achieved from increased efficiency after January 1, 2005, at a hydroelectric dam that was placed in service before January 1, 2005.

(3) The term `renewable energy' means electricity generated from—

(A) a renewable energy source; or
(B) hydrogen, other than hydrogen produced from a fossil fuel, that is produced from a renewable energy source.

(4) The term `renewable energy source' means--
(A) wind;
(B) ocean waves;
(C) biomass;
(D) solar
(E) landfill gas;
(F) incremental hydropower;
(G) livestock methane; or
(H) geothermal energy.

(5) The term `rural area' means a city, town, or unincorporated area that has a population of not more than 10,000 inhabitants.

(b) Grants- The Secretary, in consultation with the Secretary of Agriculture and the Secretary of the Interior, may provide grants under this section to eligible grantees for the purpose of--

(1) increasing energy efficiency, siting or upgrading transmission and distribution lines serving rural areas,; or

(2) providing or modernizing electric generation facilities that serve rural areas.

(c) Grant Administration-
(1) The Secretary shall make grants under this section based on a determination of cost-effectiveness and the most effective use of the funds to achieve the purposes described in subsection (b).

(2) For each fiscal year, the Secretary shall allocate grant funds under this section equally between the purposes described in paragraphs (1) and (2) of subsection (b).

(3) In making grants for the purposes described in subsection (b)(2), the Secretary shall give preference to renewable energy facilities.

(d) Authorization of Appropriations- There is authorized to be appropriated to the Secretary to carry out this section $20,000,000 for each of fiscal years 2006 through 2012.

DISCUSSION OF 2005 EPACT SMART METERING REQUIREMENTS

INTRODUCTION

Sections 1251 Net Metering And Additional Standards, Section 1252 Smart Metering and Section 1254 Interconnection of the Energy Policy Act of 2005 ("the Act" or "2005 EPAct") added five (5) new Section 111(d) standards to the Public Utility Regulatory Policies Act of 1978 ("PURPA"). Section 1251 adds three (3) new standards (Section 111(d)(11) Net Metering, Section 111(d)(12) Fuel Sources and Section 111(d)(13) Fossil Fuel Generation Efficiency). Section 1252 adds one (1) new standard (Section 111(d)(14) Time-Based Metering And Communications). Section 1254 adds one new standard (Section 111(d)(15) Interconnection). At this time, the Staff is addressing the Section 1252 Smart Metering requirements, among other reasons because it has the shortest time-frame. While the deadlines associated with other new PURPA Section 111(d) standards are not as demanding as those related to Smart Metering, the Staff mentions these so that participants are aware of them and can keep them in mind when preparing to address the Section 1252 Smart Metering requirements.

2005 EPAct Section 1252 amends various parts of PURPA, particularly Sections 111(d), 112, and 115. These provisions place some requirements on the Missouri Commission as well as the electric utilities under the Missouri Commission's jurisdiction. Some of you will recall that the Missouri Commission held formal Section 111(d) proceedings in 1980, after PURPA was enacted, and in 1993, after PURPA was amended by the Energy Policy Act of 1992.[1]

[1] There were originally six (6) Section 111(d) standards to PURPA when PURPA was enacted in 1978. Four (4) new standards were added to Section 111(d) by the Energy Policy Act of 1992.

The Staff has reviewed the recently enacted Smart Metering provisions and wishes to convey to Missouri Commission regulated electric utilities, the Office of the Public Counsel, and the entities that generally intervene in cases involving Missouri Commission regulated electric utilities, the Staff's interpretation of what is required of the Missouri Commission and how best to accomplish that which is required. The Staff is seeking your/your client's thoughts and suggestions regarding this matter.

STANDARDS FOR ELECTRIC UTILITIES

The Act requires that there be a determination at the state retail electric level whether electric utilities should offer time-based rate schedules and services so as to enable consumers to manage their energy use and costs. PURPA Section 111(a) provides that "[e]ach State regulatory authority (with respect to each electric utility for which it has ratemaking authority) . . . shall consider each standard established by subsection (d) and make a determination concerning whether or not it is appropriate to implement such standard to carry out the purposes of this title." 2005 EPAct Section 1252 amended PURPA Section 111(d) so as to include a Time-Based Metering and Communications standard ("Section 111(d)(14) Standards") for electric utilities at the retail level. Section 111(d)(14)(F) states, in relevant part, that state commissions shall conduct an investigation and issue a decision whether it is appropriate to implement the standards set out in Sections 111(d)(14)(A) and (C). If a state commission determines that the Section 111(d)(14) standard is appropriate to implement, then an electric utility is to offer each of its customer classes certain time-based rate schedules and to provide individual customers, upon customer request, a time-based meter designed to enable the provision of such electricity service.

The Act specifies four different types of time-based pricing, which may be included, among others. Listed below are the types of time-based rates promoted by the Act along with references to the specific tariff rate schedules already offered by particular Missouri Commission regulated electric utilities. As the Staff understands the Act at this time, the Staff believes that these tariffs meet the Act's desired objectives.

(i) **Time-of-Use Pricing** whereby electricity prices are set for a specific time period on an advanced or forward basis, typically not changing more often than twice a year, based on the utility's cost of generating and/or purchasing electricity at the wholesale level for the benefit of the consumer. Prices paid for energy consumed during these periods shall be pre-established and known to consumers in advance of such consumption, allowing them to vary their demand and usage in response to such prices and manage their energy costs by shifting usage to a lower cost period or reducing their consumption overall.

Seasonal Rates

All Missouri Commission regulated electric utilities have seasonal rates that are higher in the summer months (June through September) than in the winter months (October through May).

Aquila, Inc.	Empire District	KCPL	Union Electric
P.S.C. MO No. 1	*P.S.C. MO No. 5*	*P.S.C. MO No. 7*	*P.S.C. MO No. 5*

Optional Time-of-Day Rates

All Missouri Commission regulated electric utilities offer optional time-of-day rates with higher rates on peak and lower rates off peak to all of their customers.

Aquila, Inc.	Empire District	KCPL	Union Electric
L&P- Optional Time of Use Adjustment Rider *Sheet No. 35*	Optional Time of Use Adjustment Rider, Section 4 *Sheet No. 18*	Residential Time of Day Service *Sheet No. 8*	Listed with each Rate Schedule
MPS – Time of Day Residential - No. 66 General Service *Sheet No. 67*		Non-Residential Two Part - Time of Use *Sheet No. 20*	Non- Res Secondary Service Off-Peak Demand Provisions - Rider I *Sheet No. 113*
MPS - Thermal Energy Storage Pilot *Sheet No. 70*		Incremental Energy Rider *Sheet No. 24*	

Mandatory Time-of-Day Rates

Aquila, Inc.	Empire District	KCPL	Union Electric
L&P - Large Power Service *Sheet No. 35*			

(ii) **Critical Peak Pricing** whereby time-of-use prices are in effect except for certain peak days, when prices may reflect the costs of generating and/or purchasing electricity at the wholesale level and when consumers may receive additional discounts for reducing peak period energy consumption.

Time-of-Day Rates with Critical Peak Pricing

AmerenUE has a pilot/test program underway to determine the effectiveness of day-ahead notification of residential customers of a Critical Peak Pricing Period and the benefits of using a “smart” thermostat in conjunction with the program.

Aquila, Inc.	Empire District	KCPL	Union Electric
			Residential Time of Use Pilot *Sheet No. 192*

(iii) **Real-Time Pricing** whereby electricity prices are set for a specific time period on an advanced or forward basis, reflecting the utility's cost of generating and/or purchasing electricity at the wholesale level, and may change as often as hourly.

Real Time Pricing

Hourly day-ahead prices are transmitted to large non-residential customers, i.e., large industrial and commercial customers, based on expected load and market conditions. These prices apply to increases and decreases in a customer's load relative its baseline load.

Aquila, Inc.	Empire District	KCPL	Union Electric
MPS - Real Time Pricing *Sheet No. 73*	Cancelled Program – No customers	Real-Time Pricing - *Sheet No. 25* RTP - Plus *Sheet No. 26*	

(iv) **Credits for consumers with large loads** who enter into pre-established peak load reduction agreements that reduce a utility's planned capacity obligations.

Interruptible/Curtailable Rates

Customers are paid to reduce load during the highest cost hours of the summer. All Missouri Commission regulated electric utilities offer some form of interruptible/curtailable rates to large customers.

Aquila, Inc.	Empire District	KCPL	Union Electric
MPS & L&P - Voluntary[2] Load Reduction Rider *Sheet No. 96*	Interruptible[3] Rider Section 4 *Sheet No. 4*	Peak Load Curtailment[3] Rider *Sheet No. 21*	Voluntary[2] Curtailment Rider *Sheet No. 116*
MPS & L&P - Curtailable[3] Demand Rider - *Sheet No. 99*		Voluntary[2] Load Reduction Rider *Sheet No. 27*	Option Based Curtailment Rider[4] *Sheet No. 116.3*

REQUIREMENTS RESPECTING STATE COMMISSIONS

PURPA Sections 111(d)(14)(F), 112(b)(4)(A) and (B), and 115(b) direct each state regulatory commission to consider and determine whether its jurisdictional electric utilities should be required to implement the new Section 111(d)(14) standard. Section 112(e) relieves state commissions of engaging in these considerations and determinations if comparable state commission activity has occurred within the last three (3) years.

The "prior state actions" provision, PURPA Section 112(e), does not appear to apply here. Therefore, in order for the Commission to comply with the Act, the Commission will need to have commenced consideration of the applicability of the Section 111(d)(14) standard for its jurisdictional utilities no later than August 8, 2006. It would be ideal if the Commission's final determination was completed by February 8,

[2] Under these programs, the customer is offered a price per kWh to reduce its load during the curtailment period, and the customer may either accept or reject the offer.

[3] Under these programs, the customer receives a credit per kW of curtailable demand and must reduce load whenever a curtailment is called.

[4] This is a hybrid. Under this program, the customer receives an "Option Premium Payment" per MW of curtailable demand and a $/MWh "Strike Price" payment for each MWh of load reduction. If the customer fails to reduce load to the agreed level when a curtailment is called, the customer must pay the Company the "Passthrough Market Price" for each MWh it uses in excess of the contracted level.

2007. However, given the conflicting deadlines contained in the Act, a Commission determination by August 8, 2007 could arguably also meet the mandated deadline.

STAFF'S RECOMMENDATION AS TO HOW TO PROCEED

The Staff believes there is no doubt that all four electric utilities offer services which meet the Act's requirements related to Time-of-Use Pricing for all customers and Peak Load Reduction Credits for large customers. However, parties and ultimately the Commission will need to determine whether it is appropriate to require Missouri Commission regulated electric utilities to offer Critical Peak Pricing and Real-Time Pricing services to all customers. Also, PURPA Section 111(d)(14)(C) seeks to have electric utilities provide each customer requesting a time-based rate with a time-based meter capable of enabling the utility to offer and the customer to receive such rate. Therefore the Commission will also need to address whether it is appropriate for its jurisdictional electric utilities to implement this metering requirement.

At this time the Staff believes that an EO docket should be opened for the Commission to consider and determine whether Missouri Commission regulated electric utilities should be required to implement the new Section 111(d)(14) standard. If the Commission finds that specific prescriptions with respect to this standard are needed, then an EX (rulemaking) docket would, in all probability, subsequently be initiated.

Prior to opening an EO docket and even prior to deciding that an EO docket is the path to take, the Staff believes an open discussion in a roundtable format would help entities, including the Staff, determine their positions. Plans are being made for a roundtable to be held in February 2006. In order for the roundtable to be properly structured and productive, the Staff asks that each of you provide, by January 11, 2006, written comments as to your thoughts regarding Staff's preliminary views and written suggestions on how this matter should be processed.

Your assistance and cooperation in this matter will be appreciated. If you have questions, please call Dan Beck at 573-751-7522 or Denny Frey at 573-751-8700.

RELATED SECTION 1252 ACTIVITIES BY THE U.S. DEPARTMENT OF ENERGY AND THE FEDERAL ENERGY REGULATORY COMMISSION

It should also be noted that both DOE and FERC are seeking information from utilities and other industry participants to assist them in the preparation of certain reports required by 2005 EPAct. The Staff encourages you/your clients to review these inquiries and to provide the information you/your client believe to be relevant and helpful, even if it is after the stated due date.

EPAct Section 1252(d)(3) requires DOE (by February 4, 2006) to provide Congress with a report that identifies and quantifies the national benefits of demand response and makes a recommendation respecting achieving specific levels of such benefits by January 1, 2007. DOE has established a web survey seeking information regarding four (4) general areas: restructured retail markets, vertically integrated retail markets, restructured wholesale markets, and vertically-integrated wholesale markets. Responses are due November 22, 2005.

See http://www.doedemandresponsereporttocongress.com/forum.html

EPAct Section 1252(e)(3) requires FERC (by August 8, 2006) to "prepare and publish an annual report, by appropriate region, that assesses demand response resources, including those available from all consumer classes." In Docket No. AD06-2, FERC seeks comments as follows: (1) whether its proposed survey is structured so as to obtain the demand response information necessary for compiling its required report by region, and (2) regarding the six (6) areas specifically identified in EPAct Section 1252(e)(3) for which demand response information is sought. The comments regarding the structure of the survey are due December 5, 2005. Comments and information regarding the Section 1252(e)(3) information areas are due December 19, 2005.

See http://elibrary.ferc.gov:0/idmws/file_list.asp?document_id=4351968

Sections 1251 and 1254 of the Energy Policy Act of 2005 ("EPAct") amend various parts of the Public Utility Regulatory Policies Act of 1978 ("PURPA"), namely PURPA Sections 111(d), 112, and 124.

STANDARDS FOR ELECTRIC UTILITIES

As with Section 1252 of EPAct, Sections 1251 and 1254 each require that there be a determination at the state retail electric level whether electric utilities should implement the newly-promulgated PURPA standards. PURPA requires consideration of each standard by state regulatory authorities and each non-regulated electric utility. A general description of the four new standards contained in these sections of EPAct follows.

NOTE: This Commission generally does not have jurisdiction over municipal and rural electric cooperative utilities. Nonetheless, as a result of the Missouri Legislature's enactment of the Consumer Clean Energy Act (H.B. 1402) in 2002, the Commission's jurisdiction regarding net metering and interconnection includes municipal and rural electric cooperative utilities. In 2003, the Commission promulgated rules respecting net metering and interconnection, which apply to municipal and rural electric cooperative utilities in addition to investor owned electric utilities. Therefore, these municipal and rural electric cooperative utilities have an interest in this Commission's consideration and determination of whether it is appropriate to implement the new PURPA Section 111(d) standards regarding Net Metering and Interconnection.

EPAct Section 1251 - PURPA Sec. 111(d)(11) Net Metering

This standard seeks to have each electric utility make available, upon request, net metering services to any electric consumer it serves. The Commission will have to consider whether implementation of this standard is appropriate by weighing the value of avoided generation, transmission and distribution made possible by distributed generation as compared to the cost of net metering; and, if net metering proves attractive, to determine whether it is equitable for that cost to be borne by others or by the net metering customer(s).

Currently, Commission rule 4 CSR 240-20.065, Net Metering, which implements the Consumer Clean Energy Act (section 386.887, RSMo Supp. 2002), establishes standards for interconnection of qualified net metering units (generating capacity of one hundred kilowatts (100kW) or less) with retail electric power suppliers. (This same Commission rule also includes interconnection standards that relate to the new federal Interconnect Standard, which is discussed later). While the new federal standard is two sentences long, the Commission's rule is several thousand words long and addresses supplier obligations, customer-generator liability insurance obligations, determination of net value of energy, interconnection agreements, retail electric power supplier reporting requirements, and customer-generator testing requirements. In addition, a six-page Interconnection Application/Agreement for Net Metering Systems with Capacity of 100 kW or Less is also included in the state rule.

One obvious difference between the new federal standard and the Commission's rule is that the Commission rule is only applicable to units with generating capacity of one hundred kilowatts (100kW) or less, while the federal standard is silent on this matter.

EPAct Section 1251 - PURPA Sec. 111(d)(12) Fuel Sources (Fuel Diversity)

This standard requires each electric utility to develop a plan to minimize dependence on one fuel source and to ensure that the electric energy it sells to consumers is generated using a diverse range of fuels and technologies, including renewable technologies. The Commission will need to consider and weigh the limitations (increased costs associated with additional fuel sources) and advantages of diversification.

Currently, the Commission's Electric Utility Resource Planning rules (4 CSR 240-22) set minimum standards to govern the scope and objectives of the resource planning process for each investor owned-utility. While the new federal standard is one sentence long, the Commission's rules cover 15 pages. 4 CSR 240-22.040, Supply-Side Resource Analysis, specifies that both new generating plants and existing generating plant refurbishment options be considered. Probable environmental costs are to be included in any screening process. In addition, 4 CSR 240-22.060, Integrated Resource Analysis, and 4 CSR 240-22.070, Risk Analysis and Strategy Selection, also address the fuel source choices of the investor-owned utilities.

EPAct Section 1251 - PURPA Sec. 111(d)(13) Fossil Fuel Generation Efficiency

This standard seeks to have each electric utility develop and implement a 10-year plan to increase the efficiency of its fossil fuel generation. Increasing the efficiency of fossil fuel generation is likely to increase utility rates in the short run. Therefore, in deciding whether to implement this standard, the Commission will have to consider various options to see if there are ways to increase fuel efficiency while mitigating short- and long-run rate impacts.

Currently, the Commission's Electric Utility Resource Planning rules (4 CSR 240-22) set minimum standards to govern the scope and objectives of the resource planning process for each investor-owned utility. While the new federal standard is one sentence long, the Commission's rules cover 15 pages. 4 CSR 240-22.040, Supply-Side Resource Analysis, specifies that both new generating plants and existing generating plant refurbishment options be considered. Probable environmental costs are to be included in any screening process. In addition, 4 CSR 240-22.060, Integrated Resource Analysis, and 4 CSR 240-22.070, Risk Analysis and Strategy Selection, also address fossil fuel generation efficiency.

One obvious difference between the new federal standard and the Commission's rule is that the Commission's existing rule specifies a 20-year planning horizon while the federal standard requires the utilities to develop a 10-year plan.

EPAct Section 1254 - PURPA Sec. 111(d)(15) Interconnection

This standard allows electric consumers with on-site generation (sometimes called distributed generation) to connect, upon request, to its electric utility. The standard indicates that the interconnection services should be offered based on IEEE Standard 1547. It also provides that agreements and procedures will be established whereby the services offered promote the best practices of interconnection for distributed generation, including the Model Code adopted by NARUC. The Commission will need to evaluate existing standards and practices, as well as weigh the value and costs associated with providing these expanded services.

Currently, Commission rule, 4 CSR 240-20.065, Net Metering, which implements the Consumer Clean Energy Act (section 386.887, RSMo Supp. 2002), establishes standards for interconnection of qualified net metering units (generating capacity of one hundred kilowatts (100kW) or less) with retail electric power suppliers. (This same Commission rule also includes net metering standards that relate to the new federal Net

Metering Standard, which was discussed earlier). While the new federal standard is one paragraph long, the Commission's rule is several thousand words long and addresses supplier obligations, customer-generator liability insurance obligations, determination of net value of energy, interconnection agreement, retail electric power supplier reporting requirements, and customer-generator testing requirements. In addition, a six-page Interconnection Application/Agreement for Net Metering Systems with Capacity of 100 kW or Less is also included in the Commission's rule.

One obvious difference between the new federal standard and the Commission's rule is that the Commission rule is only applicable to units with generating capacity of one hundred kilowatts (100kW) or less while the federal standard is silent on this matter. Another difference is that the federal standard refers to IEEE Standard 1547 for Interconnecting Distributed Resources with Electric Power Systems while the Commission's rule does not. However, since the Commission's rule was filed before the IEEE Standards Board approved IEEE Standard 1547 and the Commission's rule does refer to "all applicable" NESC, NEC, IEEE, and UL requirements, the omission of a direct reference to IEEE Standard 1547 is understandable.

REQUIREMENTS RESPECTING STATE COMMISSIONS

State commissions are to consider the standards after public notice and a hearing. The commission determination must be in writing, based upon evidence presented, and available to the public. Prior state actions can substitute for the consideration and determination requirement, if before August 8, 2005, the state has implemented the standards (or comparable standards) for the utility; the state commission has conducted a proceeding to consider implementation of the standards (or comparable standards); or the state legislature has voted on the implementation of the standards (or comparable standards).

The deadlines associated with Sections 1251 are less demanding than those applicable to Sections 1252 and 1254. (Please refer to Attachment 1- EPAct Deadlines.)

A state's failure to comply with the prescribed deadlines triggers PURPA Section 112(c), which then requires that the consideration and determination be undertaken in the first rate case proceeding commencing after the deadline.

STAFF'S THOUGHTS AT THIS TIME ON HOW TO PROCEED

The Staff believes that a separate EO docket should be opened for each new PURPA Section 111(d) standard. A significant determination for the Commission is whether prior state actions suffice or whether further action, such as modification to existing Commission rules or new Commission rules are necessary. In order for the Commission to even make a determination that prior state actions suffice, a record would seem to be appropriate including the filing of testimony on this very matter. If parties in a case on one of the new Section 111(d) standards agree, or would not oppose, a determination by the Commission that prior state actions suffice, a stipulation and agreement would seem to be an appropriate way to proceed. If there is no agreement by the parties, then a hearing may be necessary as part of a Commission determination.

In the event the Commission finds that changes to existing rules with respect to net metering and interconnection and/or planning standards are needed, then a separate EX (rulemaking) docket would need to be initiated for each such standard/rule. The proceedings in each EO case might be viewed, in part, as a formal on-the-record workshop on that particular standard leading to either a stipulation and agreement for Commission consideration or a rulemaking.

EPAct, and the existing PURPA requirements, may be viewed as establishing a timeframe by which the Commission must decide whether to adopt a new rule or amend an existing rule. The actual adoption or amending of a rule may be completed outside of timeframe within which the Commission must make a determination whether (1) to adopt the new PURPA Section 111(d) standard or (2) it has previously addressed the new PURPA standard, taken the appropriate action based on that determination and need not do anything further.

The Staff's position at this stage is that the Commission's Net Metering Rule, 4 CSR 240-20.065, which implements the Consumer Clean Energy Act (section 386.887, RSMo Supp. 2002), constitutes prior state action, which at a minimum in part can substitute for the consideration and determination requirements related to the EPAct Sec. 1251 Net Metering and Sec. 1254 Interconnection standards. In essence, the Commission previously considered the relevant subject matter and determined to adopt, at a minimum in part, the equivalent of these new PURPA section 111(d) standards.

Similarly, the Staff's position at this stage is that the Commission's Electric Utility Resource Planning rules (4 CSR 240-22) are prior state action which can substitute for the consideration and determination requirements relative to the EPAct Sec. 1251 fuel diversity and fossil fuel generation efficiency standards. In essence, the Commission previously considered the relevant subject matter and determined to adopt, at a minimum in part, the equivalent of this new PURPA section 111(d) standard.

EPAct Deadlines for Consideration and Determination of New PURPA Standards

	By 8/8/06	By 8/8/07	By 8/8/08	
Smart Metering - PURPA Sec. 111(d)(14)	commence consideration PURPA Sec. 112(b)(4)(A)	complete determination PURPA Sec. 112(b)(4)(B)		However, it should be noted PURPA Sec. 111(d)(14)(F) indicates state commissions shall issue a decision regarding implementation by 2/8/07.
Interconnection - PURPA Sec. 111(d)(15)	commence consideration PURPA Sec. 112(b)(5)(A)	complete determination PURPA Sec. 112(b)(5)(B)		
Net Metering - PURPA Sec. 111(d)(11)		commence consideration PURPA Sec. 112(b)(3)(A)	complete determination PURPA Sec. 112(b)(3)(B)	
Fuel Diversity - PURPA Sec. 111(d)(12)		commence consideration PURPA Sec. 112(b)(3)(A)	complete determination PURPA Sec. 112(b)(3)(B)	
Fossil Fuel Generation Efficiency - PURPA Sec. 111(d)(13)		commence consideration PURPA Sec. 112(b)(3)(A)	complete determination PURPA Sec. 112(b)(3)(B)	

Rules of
Department of Economic Development
Division 240—Public Service Commission
Chapter 20—Electric Utilities

(A) Applicability. This section applies to qualifying cogeneration facilities and qualifying small power production facilities which have a power production capacity which does not exceed thirty (30) megawatts and to any qualifying small power production facility with a power production capacity over thirty (30) megawatts if that facility produces electric energy solely by the use of biomass as a primary energy source.

(B) A qualifying facility described in subsection (1)(A) shall not be considered to be an electric utility company as defined in section 2(a)(3) of the Public Utility Holding Company Act of 1935, 15 U.S.C. 79b(a)(3).

(C) Any qualifying facility shall be exempted (except as otherwise provided) from Missouri PSC law or rule respecting the rates of electric utilities and the financial and organizational regulation of electric utilities. A qualifying facility may not be exempted from Missouri PSC law and rule implementing subpart C of PURPA.

AUTHORITY: sections 386.250 and 393.140, RSMo 2000. Original rule filed Oct. 14, 1980, effective May 15, 1981. Amended: Filed Aug. 16, 2002, effective April 30, 2003.*

**Original authority: 386.250, RSMo 1939, amended 1963,1967, 1977, 1980, 1987, 1988, 1991, 1993, 1995, 1996 and 393.140, RSMo 1939, amended 1949, 1967.*

4 CSR 240-20.065 Net Metering

PURPOSE: This rule implements the Consumer Clean Energy Act (section 386.887, RSMo Supp. 2002) and establishes standards for interconnection of qualified net metering units (generating capacity of one hundred kilowatts (100 kW) or less) with retail electric power suppliers.

(1) Definitions.

(A) Commission means the Public Service Commission of the state of Missouri.

(B) Customer-generator means a consumer of electric energy who purchases electric energy from a retail electric power supplier and is the owner of a qualified net metering unit.

(C) Local distribution system means facilities for the distribution of electric energy to the ultimate consumer thereof.

(D) Qualified net metering unit means an electric generation unit which—

1. Is owned by a customer-generator;

2. Is a hydrogen fuel cell or is powered by sun, wind or biomass;

3. Has an electrical generating system with a capacity of not more than one hundred kilowatts (100 kW);

4. Is located on premises that are owned, operated, leased or otherwise controlled by the customer-generator;

5. Is interconnected with, and operates in parallel and in synchronization with a retail electric power supplier; and

6. Is intended primarily to offset part or all of the customer-generator's own electric power requirements.

(E) Retail electric power supplier means any entity that sells electric energy to the ultimate consumer thereof.

(F) Value of electric energy means the total resulting from the application of the appropriate rates, which may be time-of-use rates at the option of the retail electric power supplier, to the quantity of electric energy delivered to the retail electric power supplier from a qualified net metering unit or to the quantity of electric energy sold to a customer-generator.

(2) Applicability.

(A) This rule applies to retail electric power suppliers and customer-generators.

(3) Retail Electric Power Supplier Obligations.

(A) Each retail electric power supplier shall develop a tariff or rate schedule applicable to net metering customer-generators that shall—

1. Be made available to qualifying customer-generators upon request; and

2. Shall be posted with any other tariffs or rate schedules on the retail electric power supplier's website.

(B) Each retail electric power supplier shall provide net metering service on a first-come, first-served basis, until the total rated generating capacity used by customer-generators is equal to or in excess of the lesser of ten thousand kilowatts (10,000 kW) or one-tenth of one percent (0.1%) of the capacity necessary to meet the retail electric power supplier's aggregate customer peak demand for the preceding calendar year.

(C) Each retail electric power supplier shall notify the commission when total generating capacity of customer-generators is equal to or in excess of the lesser of ten thousand kilowatts (10,000 kW) or one-tenth of one percent (0.1%) of the capacity necessary to meet the retail electric power supplier's aggregate customer peak demand for the preceding calendar year.

(D) Each retail electric power supplier shall maintain and make available to the public, records of the total generating capacity of customer-generators, the type of generating systems and the energy sources used.

(E) The retail electric power supplier's tariff, tariff rider, or rate schedule used to provide service to the customer-generator shall be identical in rate structure, all retail rate components, and any monthly charges, to the tariff or rate schedule provisions to which the same customer would be assigned if that customer were not a customer-generator.

1. Time-of-use rates, which may be applied at the option of the retail electric power supplier, shall be the time-of-use rates applicable to the customer-generator's assigned rate classification, absent the output of the net metering unit.

(F) No retail electric power supplier's tariff or rate schedule for net metering shall require customer-generators to—

1. Perform or pay for additional tests or analysis beyond those required to determine the effect of the operation of the net metering system on the local distribution system; or

2. Purchase additional liability insurance beyond that required by section (4) of this rule.

(4) Customer-Generator Liability Insurance Obligation.

(A) The customer-generator shall carry no less than one hundred thousand dollars ($100,000) of liability insurance that provides for coverage of all risk of liability for personal injuries (including death) and damage to property arising out of or caused by the operation of the net metering unit. Insurance may be in the form of an existing policy or an endorsement on an existing policy.

(5) Determination of Net Value of Energy.

(A) Each retail electric power supplier shall calculate the net value of energy for a customer-generator in the following manner—

1. The retail electric power supplier shall individually measure both—

A. The electric energy delivered by the customer-generator to the retail electric power supplier; and

B. The electric energy provided by the retail electric power supplier to the customer-generator during each billing period by using metering capable of such function—either by a single meter capable of registering the flow of electricity in two (2) directions, or by using two (2) meters. The customer-generator is responsible for the costs of the metering described in this subsection beyond those a retail electric power supplier would incur in providing electric service to a customer in the same rate class as the customer-generator but who is not a customer-generator.

2. If the value of the electric energy supplied by the retail electric power supplier exceeds the value of the electric energy delivered by the customer-generator to the retail electric power supplier during a billing period, then the customer-generator shall be billed for the net value of the electric energy supplied by the retail electric power supplier in accordance with the rates, terms and conditions established by the retail electric power supplier for customer-generators.

3. If the value of the electric energy delivered by the customer-generator to the retail electric power supplier exceeds the value of the electric energy supplied by the retail electric power supplier, then the customer-generator—

A. Shall be billed for the appropriate customer charges for that billing period; and

B. Shall be credited for the net value of the electric energy delivered to the retail electric power supplier during the billing period, calculated using the retail electric power supplier's avoided cost (time of use or non-time of use), with this credit appearing on the customer-generator's bill no later than the following billing period.

(B) The retail electric power supplier, at its own expense, may install additional special metering (e.g. load research meter) to monitor the flow of electricity in each direction, not to include meters needed to comply with subsection (5)(A) of this rule.

(6) Interconnection Agreement.

(A) Each customer-generator and retail electric power supplier shall enter into the interconnection agreement included herein.

(7) Retail Electric Power Supplier Reporting Requirements.

(A) Each retail electric power supplier shall—

1. Supply the commission staff with a copy of the standard information regarding net metering and interconnection requirements provided to customers or posted on the retail electric power supplier's website; and

2. Supply the commission staff with a description of additional requirements, if these additional requirements are applicable to all net metering customers and not specific to individual interconnection situations, beyond those needed to meet the specific requirements outlined in section C of the interconnection agreement included herein.

(8) Customer-Generator Testing Requirements.

(A) Each customer-generator shall, at least once every year, conduct a test to confirm that the net metering unit automatically ceases to energize the output (interconnection equipment output voltage goes to zero) within two (2) seconds of being disconnected from the retail electric power supplier's system. Disconnecting the net metering unit from the retail electric power supplier's electric system at the visible disconnect switch and measuring the time required for the unit to cease to energize the output shall satisfy this test.

(B) The customer-generator shall maintain a record of the results of these tests and, upon request, shall provide a copy of the test results to the retail electric supplier.

1. If the customer-generator is unable to provide a copy of the test results upon request, the retail electric power supplier shall notify the customer-generator by mail that the customer-generator has thirty (30) days from the date the customer-generator receives the request to provide the results of a test to the retail electric power supplier.

2. If the customer-generator's equipment ever fails this test, the customer-generator shall immediately disconnect the net metering unit.

3. If the customer-generator does not provide the results of a test to the retail electric power supplier within thirty (30) days of receiving a request from the retail electric power supplier or the results of the test provided to the retail electric power supplier show that the unit is not functioning correctly, the retail electric power supplier may immediately disconnect the net metering unit.

4. The net metering unit shall not be reconnected to the retail electric power supplier's electrical system by the customer-generator until the net metering unit is repaired and operating in a normal and safe manner.

INTERCONNECTION APPLICATION/AGREEMENT FOR NET METERING SYSTEMS WITH CAPACITY OF 100 kW OR LESS

For Customers Applying for Interconnection:

If you are interested in applying for interconnection to [Utility Name]'s electrical system, you should first contact [Utility Name] and ask for information related to interconnection of parallel generation equipment to [Utility Name]'s system and you should understand this information before proceeding with this Application. If you wish to apply for interconnection to [Utility Name]'s electrical system, please complete sections A, B, C, and D, and attach the plans and specifications describing the net metering, parallel generation, and interconnection facilities (hereinafter collectively referred to as the "Customer-Generator's System") and submit them to [Utility Name] at:

[Utility Mailing Address]

You will be provided with an approval or denial of this Application within ninety (90) days of receipt by [Utility Name]. If this Application is denied, you will be provided with the reason(s) for the denial. If this Application is approved and signed by both you and [Utility Name], it shall become a binding contract and shall govern your relationship with [Utility Name].

For Customers Who Have Received Approval of Customer-Generator System Plans and Specifications:

After receiving approval of your Application, it will be necessary to construct the Customer-Generator System in compliance with the plans and specifications described in the Application, complete sections E and F of this Application, and forward this Application to [Utility Name] for review and completion of section G at:

[Utility Mailing Address]

[Utility Name] will complete the utility portion of section G and, upon receipt of a completed Application/Agreement form and payment of any applicable fees, permit interconnection of the Customer-Generator System to [Utility Name]'s electrical system within fifteen (15) days of receipt by [Utility Name] if electric service already exists to the premises, unless the Customer-Generator and [Utility Name] agree to a later date. Similarly, upon receipt of a completed Application/Agreement form and payment of any applicable fees, if electric service does not exist to the premises, [Utility Name] will permit interconnection of the Customer-Generator System to [Utility Name]'s electrical system no later than fifteen (15) days after service is established to the premises, unless the Customer-Generator and [Utility Name] agree to a later date.

For Customers Who Are Assuming Ownership or Operational Control of an Existing Customer-Generator System:

If no changes are being made to the existing Customer-Generator System, complete sections A, D and F of this Application/Agreement and forward to [Utility Name] at:

[Utility Mailing Address]

[Utility Name] will review the new Application/Agreement and shall approve such, within fifteen (15) days of receipt by [Utility Name] if the new Customer-Generator has satisfactorily completed Application/Agreement, and no changes are being proposed to the existing Customer-Generator System. There are no fees or charges for the Customer-Generator who is assuming ownership or operational control of an existing Customer-Generator System if no modifications are being proposed to that System.

A. Customer-Generator's Information
Name: ______________________________
Mailing Address: ______________________________
City: ______________________________ State: ________ Zip Code: __________
Service/Street Address (if different from above): ______________________________
City: ______________________________ State: ________ Zip Code: __________
Daytime Phone: __________________ Fax: ___________________ E-Mail: ________________________
Emergency Contact Phone: ______________________________
[Utility Name] Account No. (from Utility Bill): ______________________________

B. Customer-Generator's System Information
Manufacturer Name Plate (if applicable) AC Power Rating: _____________ kW Voltage: _________ Volts
System Type: Solar __ Wind __ Biomass __ Fuel Cell __ Other (describe) ___________________________
Service/Street Address: ______________________________
Inverter/Interconnection Equipment Manufacturer: ______________________________
Inverter/Interconnection Equipment Model No.: ______________________________
Are Required System Plans & Specifications Attached? Yes__ No __
Inverter/Interconnection Equipment Location (describe): ______________________________
____
Outdoor Manual/Utility Accessible & Lockable Disconnect Switch Location (describe):
____
Existing Electrical Service Capacity: ______ Amperes Voltage: ______ Volts
Service Character: Single Phase __ Three Phase __

C. Installation Information/Hardware and Installation Compliance
Person or Company Installing: ______________________________
Contractor's License No. (if applicable): ______________________________
Approximate Installation Date: ______________________________
Mailing Address: ______________________________
City: ______________________________ State: ________ Zip Code: __________
Daytime Phone: __________________ Fax: ___________________ E-Mail: ________________________
Person or Agency Who Will Inspect/Certify Installation: ______________________________

The Customer-Generator's proposed System hardware complies with all applicable National Electrical Safety Code (NESC), National Electric Code (NEC), Institute of Electrical and Electronics Engineers (IEEE) and Underwriters Laboratories (UL) requirements for electrical equipment and their installation. As applicable to System type, these requirements include, but are not limited to, UL 1741 and IEEE 929-2000. The proposed installation complies with all applicable local electrical codes and all reasonable safety requirements of [Utility Name]. The proposed System has a lockable, visible disconnect device, accessible at all times to [Utility Name] personnel. The System is only required to include one lockable, visible disconnect device, accessible to [Utility Name]. If the interconnection equipment is equipped with a visible, lockable, and accessible disconnect, no redundant device is needed to meet this requirement.
The Customer-Generator's proposed System has functioning controls to prevent voltage flicker, DC injection, overvoltage, undervoltage, overfrequency, underfrequency, and overcurrent, and to provide for System

synchronization to [Utility Name]'s electrical system. The proposed System does have an anti-islanding function that prevents the generator from continuing to supply power when [Utility Name]'s electric system is not energized or operating normally. If the proposed System is designed to provide uninterruptible power to critical loads, either through energy storage or back-up generation, the proposed System includes a parallel blocking scheme for this backup source that prevents any backflow of power to [Utility Name]'s electrical system when the electrical system is not energized or not operating normally.
Signed (Installer): ______________________________ Date: ______________________________________
Name (Print): ____

D. Additional Terms and Conditions
In addition to abiding by [Utility Name]'s other applicable rules and regulations, the Customer-Generator understands and agrees to the following specific terms and conditions:

1) Operation/Disconnection
If it appears to [Utility Name], at any time, in the reasonable exercise of its judgment, that operation of the Customer-Generator's System is adversely affecting safety, power quality or reliability of [Utility Name]'s electrical system, [Utility Name] may immediately disconnect and lock-out the Customer-Generator's System from [Utility Name]'s electrical system. The Customer-Generator shall permit [Utility Name]'s employees and inspectors reasonable access to inspect, test, and examine the Customer-Generator's System.

2) Liability
The Customer-Generator agrees to carry no less than $100,000 of liability insurance that provides for coverage of all risk of liability for personal injuries (including death) and damage to property arising out of or caused by the operation of the Customer-Generator's System. Insurance may be in the form of an existing policy or an endorsement on an existing policy.

3) Interconnection Costs
The Customer-Generator shall, at the Customer-Generator's cost and expense, install, operate, maintain, repair, and inspect, and shall be fully responsible for the Customer-Generator's System. The Customer-Generator further agrees to pay or reimburse to [Utility Name] all of [Utility Name]'s Interconnection Costs. Interconnection Costs are the reasonable costs incurred by [Utility Name] for: (1) additional tests or analyses of the effects of the operation of the Customer-Generator's System on [Utility Name]'s local distribution system, (2) additional metering, and (3) any necessary controls. These Interconnection Costs must be related to the installation of the physical facilities necessary to permit interconnected operation of the Customer-Generator's System with [Utility Name]'s system and shall only include those costs, or corresponding costs, which would not have been incurred by [Utility Name] in providing service to the Customer-Generator solely as a consumer of electric energy from [Utility Name] pursuant to [Utility Name]'s standard cost of service policies in effect at the time the Customer-Generator's System is first interconnected with [Utility Name]'s system. Upon request, [Utility Name] shall provide the Customer-Generator with a not-to-exceed cost statement for interconnection with [Utility Name]'s based upon the plans and specifications provided by the Customer-Generator to [Utility Name].

4) Energy Pricing and Billing
Section 386.887, RSMo Supp. 2002 sets forth the valuation and billing of electric energy provided by [Utility Name] to the Customer-Generator and to [Utility Name] from Customer-Generator. The value of the electric energy delivered to the Customer-Generator shall be billed in accordance with rate schedule(s)

Utility's Applicable Rate Schedules]. The value of the electric energy delivered by the Customer-Generator to [Utility Name] shall be credited in accordance with rate schedule(s) [Utility's Applicable Rate Schedules].

5) Terms and Termination Rights

This Agreement becomes effective when signed by both the Customer-Generator and [Utility Name], and shall continue in effect until terminated. After fulfillment of any applicable initial tariff or rate schedule term, the Customer-Generator may terminate this Agreement at any time by giving [Utility Name] at least thirty (30) days prior written notice. In such event, the Customer-Generator shall, no later than the date of termination of Agreement, completely disconnect the Customer-Generator's System from parallel operation with [Utility Name]'s system. Either party may terminate this Agreement by giving the other party at least thirty (30) days prior written notice that the other party is in default of any of the terms and conditions of this Agreement, so long as the notice specifies the basis for termination, and there is an opportunity to cure the default. This Agreement may also be terminated at any time by mutual agreement of the Customer-Generator and [Utility Name]. This agreement may also be terminated, by approval of the Commission, if there is a change in statute that is determined to be applicable to this contract and necessitates its termination.

6) Transfer of Ownership

If operational control of the Customer-Generator's System transfers to any other party than the Customer-Generator, a new Application/Agreement must be completed by the person or persons taking over operational control of the existing Customer-Generator System. [Utility Name] shall be notified no less than thirty (30) days before the Customer-Generator anticipates transfer of operational control of the Customer-Generator's System. The person or persons taking over operational control of Customer-Generator's System must file a new Application/Agreement, and must receive authorization from [Utility Name], before the existing Customer-Generator System can remain interconnected with [Utility Name]'s electrical system. The new Application/Agreement will only need to be completed to the extent necessary to affirm that the new person or persons having operational control of the existing Customer-Generator System completely understand the provisions of this Application/Agreement and agree to them. If no changes are being made to the Customer-Generator's System, completing sections A, D and F of this Application/Agreement will satisfy this requirement. If no changes are being proposed to the Customer-Generator System, [Utility Name] will assess no charges or fees for this transfer. [Utility Name] will review the new Application/Agreement and shall approve such, within fifteen (15) days if the new Customer-Generator has satisfactorily completed the Application/Agreement, and no changes are being proposed to the existing Customer-Generator System. [Utility Name] will then complete section G and forward a copy of the completed Application/Agreement back to the new Customer-Generator, thereby notifying the new Customer-Generator that the new Customer-Generator is authorized to operate the existing Customer-Generator System in parallel with [Utility Name]'s electrical system. If any changes are planned to be made to the existing Customer-Generator System that in any way may degrade or significantly alter that System's output characteristics, then the Customer-Generator shall submit to [Utility Name] a new Application/Agreement for the entire Customer-Generator System and all portions of the Application/Agreement must be completed.

7) Dispute Resolution

If any disagreements between the Customer-Generator and [Utility Name] arise that cannot be resolved through normal negotiations between them, the disagreements may be brought to the Missouri Public Service Commission by either party, through an informal or formal complaint. Procedures for filing and processing these complaints are described in 4 CSR 240-2.070. The complaint procedures described in 4 CSR 240-2.070 apply only to retail electric power suppliers to the extent that they are regulated by the Missouri Public Service Commission.

8) Testing Requirement

The Customer-Generator must, at least once every year, conduct a test to confirm that the Customer-Generator's net metering unit automatically ceases to energize the output (interconnection equipment output voltage goes to zero) within two (2) seconds of being disconnected from [Utility Name]'s electrical system. Disconnecting the net metering unit from [Utility Name]'s electrical system at the visible disconnect switch and measuring the time required for the unit to cease to energize the output shall satisfy this test. The Customer-Generator shall maintain a record of the results of these tests and, upon request by [Utility Name], shall provide a copy of the test results to [Utility Name]. If the Customer-Generator is unable to provide a copy of the test results upon request, [Utility Name] shall notify the Customer-Generator by mail that Customer-Generator has thirty (30) days from the date the Customer-Generator receives the request to provide to [Utility Name], the results of a test. If the Customer-Generator's equipment ever fails this test, the Customer-Generator shall immediately disconnect the Customer-Generator's System from [Utility Name]'s system. If the Customer-Generator does not provide results of a test to [Utility Name] within thirty (30) days of receiving a request from [Utility Name] or the results of the test provided to [Utility Name] show that the Customer-Generator's net metering unit is not functioning correctly, [Utility Name] may immediately disconnect the Customer-Generator's System from [Utility Name]'s system. The Customer-Generator's System shall not be reconnected to [Utility Name]'s electrical system by the customer-generator until the Customer-Generator's System is repaired and operating in a normal and safe manner.

I have read, understand, and accept the provisions of Section D, subsections 1 through 8 of this Application/Agreement.

Signed (Customer-Generator): ____ Date: _____________

E. Electrical Inspection

The Customer-Generator System referenced above satisfies all requirements noted in Section C.
Inspector Name (print): ____
Inspector Certification: I am a Licensed Engineer in Missouri ___ or I am a Licensed Electrician in Missouri ___ License No.____
Signed (Inspector): ____ Date: ____________

F. Customer-Generator Acknowledgement

I am aware of the Customer-Generator System installed on my premises and I have been given warranty information and/or an operational manual for that system. Also, I have been provided with a copy of [Utility Name]'s parallel generation tariff or rate schedule (as applicable) and interconnection requirements. I am familiar with the operation of the Customer-Generator System.

I agree to abide by the terms of this Application/Agreement and I agree to operate and maintain the Customer-Generator System in accordance with the manufacturer's recommended practices as well as [Utility Name]'s interconnection standards. If, at any time and for any reason, I believe that the Customer-Generator System is operating in an unusual manner that may result in any disturbances on [Utility Name]'s electrical system, I shall disconnect the Customer-Generator System and not reconnect it to [Utility Name]'s electrical system until the Customer-Generator System is operating normally after repair or inspection. Further, I agree to notify [Utility Name] no less than thirty (30) days prior to modification of the components or design of the Customer-Generator System that in any way may degrade or significantly alter that System's output characteristics. I acknowledge that any such modifications will require submission of a new Application/Agreement to [Utility Name].

I agree not to operate the Customer-Generator System in parallel with [Utility Name]'s electrical system until this Application/Agreement has been approved by [Utility Name].

Signed (Customer-Generator): ____ Date: ____________

G. Utility Application Approval (*completed by* [Utility Name])

[Utility Name] does not, by approval of this Application/Agreement, assume any responsibility or liability for damage to property or physical injury to persons due to malfunction of the Customer-Generator's System or the Customer-Generator's negligence.

This Application is approved by [Utility Name] on this ______day of ___________(month), _______(year).

[Utility Name] Representative Name (print): ____

Signed [Utility Name] Representative: ____

AUTHORITY: sections 386.250, RSMo 2000 and 386.887, RSMo Supp. 2002. Original rule filed March 11, 2003, effective Aug. 30, 2003.*

**Original authority: 386.250, RSMo 1939, amended 1963, 1967, 1977, 1987, 1988, 1991, 1993, 1995, 1996 and 386.887, RSMo 2002.*

4 CSR 240-20.070 Decommissioning Trust Funds

PURPOSE: This rule is promulgated pursuant to section 393.292, RSMo to—1) govern the review and authorization of changes to the rates and charges contained in the tariff(s) of an electric corporation as a result of a change in the level or annual accrual of funding necessary for its nuclear power plant decommissioning trust fund, 2) govern the procedure for the submission, examination, hearing and approval for the tariff changes and 3) ensure that the amounts collected from ratepayers and paid into the trust funds will be neither greater nor lesser than the amounts necessary to carry out the purposes of the trust. Additional requirements pertaining to this subject matter are also found at 4 CSR 240-3.185.

(1) As used in this rule, decommissioning means those activities undertaken in connection with a nuclear generating unit's retirement from service to ensure that the final removal, disposal, entombment or other disposition of the unit and of any radioactive components and materials associated with the unit, are accomplished in compliance with all applicable laws, and to ensure that the final disposition does not pose any undue threat to the public health and safety. Decommissioning includes the removal and disposal of the structures, systems and components of a nuclear generating unit at the time of decommissioning.

(2) As used in this rule, decommissioning costs means all reasonable costs and expenses incurred in connection with decommissioning, including all expenses to be incurred in connection with the preparation for decommissioning, including, but not limited to, engineering and other planning expenses; and to be incurred after the actual decommissioning occurs, including, but not limited to, physical security and radiation monitoring expenses, less proceeds of insurance, salvage or resale of machinery, construction equipment or apparatus the cost of which was charged as a decommissioning expense.

(3) As used in this rule, utility(ies) means all electrical corporations subject to the jurisdiction of the Missouri Public Service Commission (commission) that own, in whole or in part, or operate nuclear generating units in Missouri or elsewhere and that have costs of these units reflected in the rates charged to Missouri ratepayers.

(4) Each utility shall establish a tax-qualified externally managed trust fund for the purpose of collecting funds to pay for decommissioning costs. The tax-qualified trust shall be established and maintained in accordance with the provisions of the *Internal Revenue Code*. If the utility has collected funds in excess of the Internal Revenue Service's (IRS) tax-qualified amount, a nontax-qualified externally managed trust fund shall be established and maintained for all these funds. These trust funds shall be administered pursuant to the following requirements:

(A) Each utility shall submit a copy of the decommissioning trust agreement and any other agreement entered into between the utility, trustee and investment manager(s) for approval by the commission. The listing of trustee fees shall be contained in or attached to the trust agreement itself. Any change in the trust agreement, trustee or investment manager(s) also shall be submitted to the commission for approval;

(B) The commission shall have the authority to require each utility to change the trustee or investment manager(s) of a decommissioning trust for good cause shown. The commission shall be informed of any significant disputes between the utility, the trustee or investment manager(s);

(C) Each utility shall maintain separate tax qualified trusts for each nuclear generating unit. All decommissioning trusts shall be maintained to show the amounts contributed annually by Missouri jurisdictional customers. Amounts to be contributed annually for Missouri jurisdictional customers shall be computed based on the jurisdictional allocator used in the company's last general rate proceeding unless otherwise ordered by the commission;

(D) The decommissioning trust shall be funded through no less than quarterly payments by the utility. The tax-qualified trust shall be funded with the lesser of the utility's decommissioning costs reflected in its cost of service or the maximum amount allowable by the IRS. All funds in excess of the IRS's ruling amount shall be placed in a nonqualified trust;

(E) The trustee or investment manager(s) shall invest the tax-qualified trust assets and nontax-qualified trust assets only in assets that are prudent investments for assets held in trust and in a manner designed to maximize the after-tax return on funds invested, consistent with the conservation of the principal, subject to the limitations specified as follows:

1. The trustee and investment manager(s) shall not invest any portion of the tax-qualified or nontax-qualified trust's funds in the securities or assets of the following:

A. Any owner or operator of a nuclear power plant;

B. Any index fund, mutual fund or pooled fund in which more than fifteen percent (15%) of the assets are issued by owners or operators of nuclear power plants;

C. Any affiliated company of the utility; or

D. The trustee or investment manager's(s') company or affiliated companies (This limitation does not include time or demand deposits offered through the trustee or investment manager's(s') affiliated banking operations.);

2. The nontax-qualified trust shall be subject to the prohibitions against self-dealing applicable to the tax qualified trust as specified in the *Internal Revenue Code*; and

3. A utility's total book value of investments in equity securities in all of its decommissioning trusts shall not exceed sixty-five percent (65%) of the trust funds' book value; and

(F) All income earned by a trust's funds shall become a part of that trust's funds.

(5) The utility shall take every reasonable action to provide reasonable assurance that adequate funds are available at the nuclear generating unit's termination of operation, so that decommissioning can be carried out in a safe and timely manner and that lack of funds does not result in delays that may cause undue health and safety hazards.

(6) The utility shall maintain its nuclear generating unit(s) in a manner calculated to minimize the utility's total cost of maintenance and decommissioning, consistent with the prudent operation of the unit.

(7) Upon the filing of the appropriate tariff(s) as set in 4 CSR 240-3.180, the commission shall establish a schedule of proceedings which shall be limited in scope to the following issues:

(A) The extent of any change in the level or annual accrual of funding necessary for the utility's decommissioning trust fund; and

(B) The changes in rates which would reflect any change in the funding level or accrual rate.

Rules of

Department of Economic Development

Division 240—Public Service Commission
Chapter 22—Electric Utility Resource Planning

Title **Page**

Title 4—DEPARTMENT OF ECONOMIC DEVELOPMENT
Division 240—Public Service Commission
Chapter 22—Electric Utility Resource Planning

4 CSR 240-22.010 Policy Objectives

PURPOSE: This rule states the public policy goal that this chapter is designed to achieve and identifies the objectives that the electric utility resource planning process must serve.

(1) The commission's policy goal in promulgating this chapter is to set minimum standards to govern the scope and objectives of the resource planning process that is required of electric utilities subject to its jurisdiction in order to ensure that the public interest is adequately served. Compliance with these rules shall not be construed to result in commission approval of the utility's resource plans, resource acquisition strategies or investment decisions.

(2) The fundamental objective of the resource planning process at electric utilities shall be to provide the public with energy services that are safe, reliable and efficient, at just and reasonable rates, in a manner that serves the public interest. This objective requires that the utility shall—

(A) Consider and analyze demand-side efficiency and energy management measures on an equivalent basis with supply-side alternatives in the resource planning process;

(B) Use minimization of the present worth of long-run utility costs as the primary selection criterion in choosing the preferred resource plan; and

(C) Explicitly identify and, where possible, quantitatively analyze any other considerations which are critical to meeting the fundamental objective of the resource planning process, but which may constrain or limit the minimization of the present worth of expected utility costs. The utility shall document the process and rationale used by decision makers to assess the tradeoffs and determine the appropriate balance between minimization of expected utility costs and these other considerations in selecting the preferred resource plan and developing contingency options. These considerations shall include, but are not necessarily limited to, mitigation of—

1. Risks associated with critical uncertain factors that will affect the actual costs associated with alternative resource plans;

2. Risks associated with new or more stringent environmental laws or regulations that may be imposed at some point within the planning horizon; and

3. Rate increases associated with alternative resource plans.

AUTHORITY: sections 386.040, 386.610 and 393.140, RSMo 1986 and 386.250, RSMo Supp. 1991. Original rule filed June 12, 1992, effective May 6, 1993.*

**Original authority: 386.040, RSMo 1939; 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991; 386.610, RSMo 1939; and 393.140, RSMo 1939, amended 1949, 1967.*

4 CSR 240-22.020 Definitions

PURPOSE: This rule defines terms used in the rules comprising 4 CSR 240-22—Electric Utility Resource Planning.

PUBLISHER'S NOTE: The publication of the full text of the material that the adopting agency has incorporated by reference in this rule would be unduly cumbersome or expensive. Therefore, the full text of that material will be made available to any interested person at both the Office of the Secretary of State and the office of the adopting agency, pursuant to section 536.031.4, RSMo. Such material will be provided at the cost established by state law.

(1) Avoided cost means the cost savings obtained by substituting demand-side resources for existing and new supply resources. 4 CSR 240-22.050(2) requires the utility to develop the following measures of avoided cost:

(A) Avoided utility costs developed pursuant to 4 CSR 240-22.050(2)(D), which include energy cost savings plus demand cost savings associated with generation, transmission and distribution facilities; and

(B) Avoided probable environmental costs developed pursuant to 4 CSR 240-22.050 (2)(D) and 4 CSR 240-22.040(2)(B).

(2) Candidate resource options are demand-side programs that pass the screening test required by 4 CSR 240-22.050(7), or supply-side resources that are not rejected on the basis of the screening analysis required by 4 CSR 240-22.040(2).

(3) Capacity means the maximum capability to continuously produce and deliver electric power via supply-side resources or the avoidance of the need for this capability by demand-side resources.

(4) Chance node is a decision-tree fork consisting of two (2) or more branches that represent the range and number of relevant potential outcomes for an uncertain factor.

(5) Coincident demand means the hourly demand of a component of system load at the hour of system peak demand within a specified interval of time.

(6) Contingency option means an alternative choice, decision or course of action designed to enhance the utility's ability to respond quickly and appropriately to events or circumstances that would render the preferred resource plan obsolete.

(7) Decision node is a decision-tree fork consisting of two (2) or more branches that represent the set of decision alternatives being considered by utility planners at that stage of the resource planning process.

(8) Decision tree is a diagram that specifies the order in which key resource decisions must be made, enumerates the set of decision alternatives to be considered at each stage, identifies the critical uncertain factors that affect the outcome of each decision and shows how the potential range of values for uncertain factors interact with each decision option to affect the expected cost of providing an adequate level and quality of energy services.

(9) Demand means the rate of electric power use measured in kilowatts (kW).

(10) Demand-side measure is synonymous with end-use measure.

(11) Demand-side resource (or program) means an organized process for packaging and delivering to a particular market segment a portfolio of end-use measures that is broad enough to include at least some measures that are appropriate for most members of the target market segment.

(12) Driver variable means an external economic or demographic factor that significantly affects some component of utility loads.

(13) Electric utility or utility means any electrical corporation as defined in section 386.020, RSMo which is subject to the jurisdiction of the commission.

(14) End-use energy service or energy service means the specific need that is served by the final use of energy, such as lighting, cooking, space heating, air conditioning, refrigeration, water heating or motive power.

(15) End-use measure means an energy-efficiency measure or an energy-management measure.

(16) Energy means the total amount of electric power that is generated or used over a specified interval of time measured in kilowatt-hours (kWh).

(17) Energy-efficiency measure means any device, technology, rate structure or operating procedure that makes it possible to deliver an adequate level and quality of end-use energy service while using less energy than would otherwise be required.

(18) Energy-management measure means any device, technology, rate structure or operating procedure that makes it possible to alter the time pattern of electricity usage so as to require less generating capacity or to allow the electric power to be supplied from more fuel-efficient generating units.

(19) Expected cost of an alternative resource plan is the statistical expectation of the cost of implementing that plan, contingent upon the uncertain factors and associated subjective probabilities represented by chance nodes in the decision tree. 4 CSR 240-22.060 requires the utility to consider probable environmental costs as well as direct utility costs in its assessment of alternative resource plans.

(20) Expected unserved hours means the statistical expectation of the number of hours per year that a utility will be unable to supply its native load without importing emergency power.

(21) Fixed cost margin means the portion of electric energy and demand rates that is designed to recover all nonvariable costs.

(22) Implementation period means the time interval between the filings required of each utility pursuant to 4 CSR 240-22.080.

(23) Implementation plan means descriptions and schedules for the major tasks necessary to implement the preferred resource plan over the implementation period.

(24) Inefficient energy-related choice means any decision that causes the life-cycle cost of delivering an adequate level and quality of end-use energy service to be higher than it would be for an available alternative choice.

(25) Inefficient price means a price that is not equal to the long-run marginal cost of providing a good or service.

(26) Information means any fact, relationship, insight, estimate or expert judgment that narrows the range of uncertainty surrounding key decision variables or has the potential to substantially influence or alter resource- planning decisions.

(27) Levelized cost means the dollar amount of a fixed annual payment for which a stream of those payments over a specified period of time is equal to a specified present value based on a specified rate of interest.

(28) Life-cycle cost means the present worth of costs over the lifetime of any device or means for delivering end-use energy service.

(29) Load-building program means an organized promotional effort by the utility to persuade energy-related decision-makers to choose electricity instead of other forms of energy for the provision of energy service or to persuade existing customers to increase their use of electricity, either by substituting electricity for other forms of energy or by increasing the level or variety of energy services used. This term is not intended to include the provision of technical or engineering assistance, information about filed rates and tariffs, or other forms of routine customer service.

(30) Load duration curve is a plot of ranked hourly demand versus the number of hours in which demand was greater than or equal to that value over a specified interval of time.

(31) Load factor means the average demand over a specified interval of time divided by the maximum demand in the interval.

(32) Load impact means the change in energy usage and the change in diversified demand during a specified interval of time due to the implementation of a demand-side measure or program.

(33) Load profile means a plot of hourly demand versus chronological hour of the day from the hour ending 1:00 a.m. to the hour ending 12:00 midnight.

(34) Load-research data means average hourly demands (kWhs per hour) derived from the metered instantaneous demand for each customer in the load-research sample.

(35) Load-research estimates, or class hourly loads, or class load estimates means the statistical expectation of the average hourly demands for each major class derived from the load-research data for that class.

(36) Load-research sample means a subset of utility customers from each major class whose demands are metered to provide statistical estimates of class hourly loads to a specified level of accuracy.

(37) Long run means an analytical framework within which all factors of production are variable.

(38) Lost margin or lost revenues means the reduction between rate cases in billed demand (kW) and energy (kWh) due to installed demand-side measures, multiplied by the fixed-cost margin of the appropriate rate component.

(39) Market imperfection means any factor or situation that contributes to inefficient energy-related choices by decision-makers, including at least—

(A) Inadequate information about costs, performance and benefits of end-use measures;

(B) Inadequate marketing infrastructure or delivery channels for end-use measures;

(C) Inadequate financing options for end-use measures;

(D) Mismatched economic incentives resulting from situations where the person who pays the initial cost of an efficiency investment is different from the person who pays the operating costs associated with the chosen efficiency level;

(E) Ineffective economic incentives when decision-makers give low priority to energy-related choices because they have a short-term ownership perspective or because energy costs are a relatively small share of the total cost structure (for businesses) or of the total budget (for households); or

(F) Inefficient pricing of energy supplies.

(40) Market segment means any subgroup of utility customers (or other energy-related decision-makers) which has some or all of the following characteristics in common: they have a similar mix of end-use energy service needs, they are subject to a similar array of market imperfections that tend to inhibit efficient energy-related choices, they have similar values and priorities concerning energy-related choices, or the utility has access to them through similar channels or modes of communication.

(41) Nominal dollars mean future or then-current dollar values that are not adjusted to remove the effects of anticipated inflation.

(42) Participant means an energy-related decision-maker who implements one (1) or

more end-use measures as a direct result of a demand-side program.

(43) Planning horizon means a future time period of at least twenty (20) years' duration over which the costs and benefits of alternative resource plans are evaluated.

(44) Preferred resource plan means the resource plan that is contained in the resource acquisition strategy that has most recently been adopted for implementation by the electric utility.

(45) Probable environmental benefits test is a test of the cost-effectiveness of end-use measures that uses the sum of avoided utility costs and avoided probable environmental costs to quantify the savings obtained by substituting the end-use measure for supply resources.

(46) Probable environmental cost means the expected cost to the utility of complying with new or additional environmental laws, regulations, taxes or other requirements that utility decision-makers judge may be imposed at some point within the planning horizon which would result in compliance costs that could have a significant impact on utility rates.

(47) Resource acquisition strategy means a preferred resource plan, an implementation plan and a set of contingency options for responding to events or circumstances that would render the preferred plan obsolete.

(48) Resource plan means a particular combination of demand-side and supply-side resources to be acquired according to a specified schedule over the planning horizon.

(49) Resource planning means the process by which an electric utility evaluates and chooses the appropriate mix and schedule of supply-side and demand-side resource additions to provide the public with an adequate level, quality and variety of end-use energy services.

(50) Screening test or cost-effectiveness test means the probable environmental benefits test for demand-side measures and the total resource cost test for demand-side programs.

(51) Subjective probability means the judgmental likelihood that the outcome represented by each branch of a chance node will actually occur. The sum of the probabilities associated with the branches of a single chance node must equal one (1). This means that the specified set of potential outcomes must be exhaustive and mutually exclusive.

(52) Sulfur dioxide emission allowance is an authorization to emit, during or after a specified calendar year, one (1) ton of sulfur dioxide, as defined in Title IV of the Clean Air Act Amendments of 1990, 42 U.S.C. 7651a(3).

(53) Supply-side resource or supply resource means any device or method by which the electric utility can provide to its customers an adequate level and quality of electric power supply.

(54) Technical potential of an end-use measure is an estimate of the load impact that would occur if that measure were installed at every location in the utility's service territory where the measure is technically feasible but has not yet been installed.

(55) Total resource cost test is a test of the cost-effectiveness of demand-side programs that compares the sum of avoided utility costs plus avoided probable environmental costs to the sum of all incremental costs of end-use measures that are implemented due to the program (including both utility and participant contributions), plus utility costs to administer, deliver and evaluate each demand-side program to quantify the net savings obtained by substituting the demand-side program for supply resources.

(56) Uncertain factor means any event, circumstance, situation, relationship, causal linkage, price, cost, value, response or other relevant quantity which can materially affect the outcome of resource planning decisions, about which utility planners and decision-makers have incomplete or inadequate information at the time a decision must be made.

(57) Utility costs are the costs of operating the utility system and developing and implementing a resource plan that are incurred and paid by the utility. On an annual basis, utility cost is synonymous with utility revenue requirement.

(58) The utility cost test is a test of the cost-effectiveness of demand-side programs that compares the avoided utility costs to the sum of all utility incentive payments, plus utility costs to administer, deliver and evaluate each demand-side program to quantify the net savings obtained by substituting the demand-side program for supply resources.

(59) The utility benefits test is a test of the cost-effectiveness of end-use measures that uses avoided utility costs to quantify the savings obtained by substituting the end-use measure for supply resources.

(60) Utility discount rate means the post-tax rate of return on net investment used to calculate the utility's annual revenue requirements.

(61) Weather measure means a function of daily temperature data that reflects the observed relationship between electric load and temperature.

AUTHORITY: sections 386.040, 386.610 and 393.140, RSMo 1986 and 386.250, RSMo Supp. 1991. Original rule filed June 12, 1992, effective May 6, 1993.*

**Original authority: 386.040, RSMo 1939; 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991; 386.610, RSMo 1939; and 393.140, RSMo 1939, amended 1949, 1967.*

4 CSR 240-22.030 Load Analysis and Forecasting

PURPOSE: This rule sets minimum standards for the maintenance and updating of historical data, the level of detail required in analyzing and forecasting loads, and for the documentation of the inputs, components and methods used to derive the load forecasts.

(1) Historical Data Base. The utility shall develop and maintain data on the actual historical patterns of energy usage within its service territory. The following information shall be maintained and updated on an ongoing basis:

(A) Customer Class Detail. The historical data base shall be maintained for each of the following major classes: residential, commercial, industrial, interruptible and other classes that may be required for forecasting (for example, large power, wholesale, outdoor lighting and public authorities).

1. Taking into account the requirement for an unbiased forecast as well as the cost of developing data at the subclass level, the utility shall determine what level of subclass detail is required for forecasting and what methods to use in gathering subclass information for each major class.

2. The utility shall consider the following categories of subclasses: for residential, dwelling type; for commercial, building or business type; and for industrial, product type. If the utility uses subclasses which do not fit into these categories, it must explain the reasons for its choice of subclasses;

(B) Load Data Detail. The historical load data base shall contain the following data:

1. For each jurisdiction under which the utility has rates established and for which it prepares customer and energy forecasts, each major class, and to the extent data is required

to support the detail specified in paragraph (1)(A)1., for each subclass, actual monthly energy usage and number of customers and weather-normalized monthly energy usage;

2. For each major class, estimated actual and weather-normalized demands at the time of monthly system peaks; and

3. For the system, actual and weather-normalized hourly net system load;

(C) Load Component Detail. The historical data base for major class monthly energy usage and demands at time of monthly peaks shall be disaggregated into a number of units component and a use kilowatt-hour (kWh) per unit component, for both actual and weather-normalized loads.

1. Typical units for the major classes are—residential, number of customers; commercial, square feet of floor space or commercial employment level; and industrial, production output or employment level. If the utility uses a different unit measure, it must explain the reason for choosing different units.

2. The utility shall develop and implement a procedure to routinely measure and regularly update estimates of the effect of departures from normal weather on class and system electric loads.

A. The estimates of the effect of weather on class and system loads shall incorporate the nonlinear response of loads to daily weather and seasonal variations in loads.

B. For at least the base year of the forecast, the utility shall estimate the cooling, heating and nonweather-sensitive components of the weather-normalized major class loads.

C. The utility shall document the methods used to develop weather measures and the methods used to estimate the effect of weather on electric loads. If statistical models are used, the documentation shall include at least: the functional form of the models; the estimation techniques employed; the data used to estimate the models, including the development of model input data from basic data; and the relevant statistical results of the models, including parameter estimates and tests of statistical significance; and

(D) Length of Data Base. Once the utility has developed the historical data base, it shall retain that data base for the ten (10) most recent years or for the period of time used as the basis of the utility's forecast, whichever is longer.

1. The development of actual and weather-normalized monthly class and system energy usage and actual hourly net system loads shall start from January 1982 or for the period of time used as the basis of the utility's forecast of these loads, whichever is longer.

2. Estimated actual and weather-normalized class and system monthly demands at the time of the system peak and weather-normalized hourly system loads shall start from January 1990 or for the period of time used as the basis of the utility's forecast of these loads, whichever is longer.

(2) Analysis of Number of Units. For each major class or subclass, the utility shall analyze the historical relationship between the number of units and the economic or demographic factors (driver variables) that affect the number of units for that major class or subclass. These relationships shall be specified as statistical or mathematical models that relate the number of units to the driver variables.

(A) Choice of Driver Variables. The utility shall identify appropriate driver variables as predictors of the number of units for each major class or subclass. The critical assumptions that influence the driver variables shall also be identified.

(B) Documentation of statistical models shall include the elements specified in subparagraph (1)(C)2.C. Documentation of mathematical models shall include a specification of the functional form of the equations.

(C) Where the utility has modeled the relationship between the number of units and the driver variables for a major class, but not for subclasses within that major class, it shall consider how a change in the subclass shares of major class units could affect the major class forecast.

(3) Analysis of Use Per Unit. For each major class, the utility shall analyze historical use per unit by end use.

(A) End-Use Detail. For each major class, use per unit shall be disaggregated by end use where information permits.

1. Where applicable for each major class, end-use information shall be developed for at least lighting, process equipment, space cooling, space heating, water heating and refrigeration.

2. For each major class and each end use, including those listed in paragraph (3)(A)1., if information is not available, the utility shall provide a schedule for acquiring this end-use information or demonstrate that either the expected costs of acquisition were found to outweigh the expected benefits over the planning horizon or that gathering the end-use information has proven to be infeasible.

3. If the utility has not yet acquired end-use information on space cooling or space heating for a major class, the utility shall determine the effect that weather has on the total load of that major class by disaggregating the load into its cooling, heating and non-weather-sensitive components. If the cooling or heating components are a significant portion of the total load of the major class, then the cooling or heating components of that load shall be designated as end uses for that major class.

4. The difference between the total load of a major class and all end uses for which the utility has acquired end-use information shall be designated as an end use for that major class.

(B) The data base and historical analysis required for each end use shall include at least the following:

1. Measures of the stock of energy-using capital goods. For each major class and end use, the utility shall implement a procedure to develop and maintain survey data on the energy-related characteristics of the building, appliance and equipment stock including saturation levels, efficiency levels and sizes where applicable. The utility shall update these surveys before each scheduled filing pursuant to 4 CSR 240-22.080; and

2. Estimates of end-use energy and demand. For each end use, the utility shall estimate end-use monthly energies and demands at time of monthly system peaks and shall calibrate these energies and demands to equal the weather-normalized monthly energies and demands at time of monthly peaks for each major class for the most recently available data.

(4) Analysis of Load Profiles. The utility shall develop a consistent set of daily load profiles for the most recent year for which data is available. For each month, load profiles shall be developed for a peak weekday, a representative of at least one (1) weekday and a representative of at least one (1) weekend day.

(A) Load profiles for each day type shall be developed for each end use, for each major class and for the net system load.

(B) For each day type, the estimated end-use load profiles shall be calibrated to sum to the estimated major class load profiles and the estimated major class load profiles shall be calibrated to sum to the net system load profiles.

(5) Base-Case Load Forecast. The utility's base-case load forecast shall be based on projections of the major economic and demographic driver variables that utility decision-makers believe to be most likely. All components of the base-case forecast shall be based on the assumption of normal weather conditions. The load impacts of implemented

demand-side programs shall be incorporated in the base-case load forecast but the load impacts of proposed demand-side programs shall not be included in the base-case forecast.

(A) Customer Class and Total Load Detail. The utility shall produce forecasts of monthly energy usage and demands at the time of the summer and winter system peaks by major class for each year of the planning horizon. Where the utility anticipates that jurisdictional levels of forecasts will be required to meet the requirements of a specific state, then the utility shall determine a procedure by which the major class forecasts can be separated by jurisdictional component.

(B) Load Component Detail. For each major class, the utility shall produce separate forecasts of the number of units and use per unit components based on the analysis described in sections (2) and (3) of this rule.

1. Number of units forecast. The utility's forecast of number of units for each major class shall be based on the analysis of the relationship between number of units and driver variables described in section (2). Where judgment has been applied to modify the results of a statistical or mathematical model, the utility shall specify the factors which caused the modification and shall explain how those factors were quantified.

A. The forecasts of the driver variables shall be specified and clearly documented. These forecasts shall be compared to historical trends and significant differences between the forecasts and long-term and recent trends shall be analyzed and explained.

B. The forecasts of the number of units for each major class shall be compared to historical trends. Significant differences between the forecasts and long-term and recent trends shall be analyzed and explained.

2. Use per unit forecast. The utility's forecast of monthly energy usage per unit and seasonal peak demands per unit for each major class shall be based on the analysis described in section (3).

A. The forecasts of the driver variables for the use per unit shall be specified. The utility shall document how the forecast of use per unit has taken into account the effects of real prices of electricity, real prices of competitive energy sources, real incomes and any other relevant economic and demographic factors.

B. End-use detail. For each major class and for each end use, the utility shall forecast both monthly energy use and demands at time of the summer and winter system peaks.

C. The stock of energy-using capital goods. For each end use for which the utility has developed measures of the stock of energy-using capital goods and where the utility has determined that forecasting the use of electricity associated with these energy-using capital goods is cost-effective and feasible, it shall forecast those measures and document the relationship between the forecasts of the measures to the forecasts of end-use energy and demands at time of the summer and winter system peaks. The values of the driver variables used to generate forecasts of the measures of the stock of energy-using capital goods shall be specified and clearly documented.

D. The major class forecasted use per unit shall be compared to historical trends in weather-normalized use per unit. Significant differences between the forecasts and long-term and recent trends shall be analyzed and explained.

(C) Net System Load Forecast. The utility shall produce a forecast of net system load profiles for each year of the planning horizon. The net system load forecast shall be consistent with the utility's forecasts of monthly energy and demands at time of summer and winter system peaks for the major rate classes.

(6) Sensitivity Analysis. The utility shall analyze the sensitivity of the components of the base-case forecast for each major class to variations in the key driver variables, including the real price of electricity, the real price of competing fuels and economic and demographic factors identified in section (2) and subparagraph (5)(B)2.A.

(7) High-Case and Low-Case Load Forecasts. Based on the sensitivity analysis described in section (6), the utility shall produce at least two (2) additional load forecasts (a high-growth case and a low-growth case) that bracket the base-case load forecast. Subjective probabilities shall be assigned to each of the load forecast cases. These forecasts and associated subjective probabilities shall be used as inputs to the strategic risk analysis required by 4 CSR 240-22.070.

(8) Reporting Requirements. To demonstrate compliance with the provisions of this rule, and pursuant to the requirements of 4 CSR 240-22.080, the utility shall prepare a report that contains at least the following information:

(A) For each major class specified in subsection (1)(A), the utility shall provide plots of number of units, energy usage per unit and total class energy usage.

1. Plots shall be produced for the summer period (June through September), the remaining nonsummer months and the calendar year.

2. The plots shall cover the historical data base period and the forecast period of at least twenty (20) years.

A. The historical period shall include both actual and weather-normalized energy usage per unit and total class energy usage.

B. The plots for the forecast period shall show each end-use component of major class energy usage per unit and total class energy usage for the base-case forecast.

(B) For each major class specified in subsection (1)(A), the utility shall provide plots of class demand per unit and class total demand at time of summer and winter system peak. The plots shall cover the historical data base period and the forecast period of at least twenty (20) years.

1. The plots for the historical period shall include both actual and weather-normalized class demands per unit and total demands at the time of summer and winter system peak demands.

2. The plots for the forecast period shall show each end-use component of major class coincident demands per unit and total class coincident demands for the base-case forecast.

(C) For the forecast of class energy and peak demands, the utility shall provide a summary of the sensitivity analysis required by section (6) of this rule that shows how changes in the driver variables affect the forecast.

(D) For the net system load, the utility shall provide plots of energy usage and peak demand.

1. The energy plots shall include the summer, nonsummer and total energy usage for each calendar year.

2. The peak demand plots shall include the summer and winter peak demands.

3. The plots shall cover the historical data base period and the forecast period of at least twenty (20) years. The historical period shall include both actual and weather-normalized values. The forecast period shall include the base-case, low-case and high-case forecasts.

4. The utility shall describe how the subjective probabilities assigned to each forecast were determined.

(E) For each major class, the utility shall provide estimated load profile plots for the summer and winter system peak days.

1. The plots shall show each end-use component of the hourly load profile.

2. The plots shall be provided for the base year of the load forecast and for the fifth, tenth and twentieth years of the forecast.

(F) For the net system load profiles, the utility shall provide plots for the summer peak day and the winter peak day.

1. The plots shall show each of the major class components of the net system load profile in a cumulative manner.

2. The plots shall be provided for the base year of the forecast and for the fifth, tenth and twentieth years of the forecast.

(G) The data presented in all plots also shall be provided in tabular form.

(H) The utility shall provide a description of the methods used to develop all forecasts required by this rule, including an annotated summary that shows how these methods comply with the specific provisions of this rule. If end-use methods have not been used in forecasting, an explanation as to why they have not been used shall be included. Also included shall be the utility's schedule to acquire end-use information and to develop end-use forecasting techniques or a discussion as to why the acquisition of end-use information and the development of end-use forecasting techniques are either impractical or not cost-effective.

AUTHORITY: sections 386.040, 386.610 and 393.140, RSMo 1986 and 386.250, RSMo Supp. 1991. Original rule filed June 12, 1992, effective May 6, 1993.*

**Original authority: 386.040, RSMo 1939; 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991; 386.610, RSMo 1939; and 393.140, RSMo 1939, amended 1949, 1967.*

4 CSR 240-22.040 Supply-Side Resource Analysis

PURPOSE: This rule establishes minimum standards for the scope and level of detail required in supply-side resource analysis.

(1) The analysis of supply-side resources shall begin with the identification of a variety of potential supply-side resource options which the utility can reasonably expect to develop and implement solely through its own resources or for which it will be a major participant. These options include new plants using existing generation technologies; new plants using new generation technologies; life extension and refurbishment at existing generating plants; enhancement of the emission controls at existing or new generating plants; purchased power from utility sources, cogenerators or independent power producers; efficiency improvements which reduce the utility's own use of energy; and upgrading of the transmission and distribution systems to reduce power and energy losses. The utility shall collect generic cost and performance information for each of these potential resource options which shall include at least the following attributes where applicable:

(A) Fuel type and feasible variations in fuel type or quality;

(B) Practical size range;

(C) Maturity of the technology;

(D) Lead time for permitting, design, construction, testing and startup;

(E) Capital cost per kilowatt;

(F) Annual fixed operation and maintenance costs;

(G) Annual variable operation and maintenance costs;

(H) Scheduled routine maintenance outage requirements;

(I) Equivalent forced-outage rates or full-and partial-forced-outage rates;

(J) Operational characteristics and constraints of significance in the screening process;

(K) Environmental impacts, including at least the following:

1. Air emissions including at least the primary acid gases, greenhouse gases, ozone precursors, particulates and air toxics;

2. Waste generation including at least the primary forms of solid, liquid, radioactive and hazardous wastes;

3. Water impacts including direct usage and at least the primary pollutant discharges, thermal discharges and groundwater effects; and

4. Siting impacts and constraints of sufficient importance to affect the screening process; and

(L) Other characteristics that may make the technology particularly appropriate as a contingency option under extreme outcomes for the critical uncertain factors identified pursuant to 4 CSR 240-22.070(2).

(2) Each of the supply-side resource options referred to in section (1) shall be subjected to a preliminary screening analysis. The purpose of this step is to provide an initial ranking of these options based on their relative annualized utility costs as well as their probable environmental costs and to eliminate from further consideration those options that have significant disadvantages in terms of utility costs, environmental costs, operational efficiency, risk reduction or planning flexibility, as compared to other available supply-side resource options. All costs shall be expressed in nominal dollars.

(A) Cost rankings shall be based on estimates of the installed capital costs plus fixed and variable operation and maintenance costs levelized over the useful life of the resource using the utility discount rate. In lieu of levelized cost, the utility may use an economic carrying charge annualization in which the annual dollar amount increases each year at an assumed inflation rate and for which a stream of these amounts over the life of the resource yields the same present value.

(B) The probable environmental costs of each supply-side resource option shall be quantified by estimating the cost to the utility to comply with additional environmental laws or regulations that may be imposed at some point within the planning horizon.

1. The utility shall identify a list of environmental pollutants for which, in the judgment of utility decision-makers, additional laws or regulations may be imposed at some point within the planning horizon which would result in compliance costs that could have a significant impact on utility rates.

2. For each pollutant identified pursuant to paragraph (2)(B)1., the utility shall specify at least two (2) levels of mitigation that are more stringent than existing requirements which are judged to have a nonzero probability of being imposed at some point within the planning horizon.

3. For each mitigation level identified pursuant to paragraph (2)(B)2., the utility shall specify a subjective probability that represents utility decision-maker's judgment of the likelihood that additional laws or regulations requiring that level of mitigation will be imposed at some point within the planning horizon. The utility, based on these probabilities, shall calculate an expected mitigation level for each identified pollutant.

4. The probable environmental cost for a supply-side resource shall be estimated as the joint cost of simultaneously achieving the expected level of mitigation for all identified pollutants emitted by the resource. The estimated mitigation costs for an environmental pollutant may include or may be entirely comprised of a tax or surcharge imposed on emissions of that pollutant.

(C) The utility shall rank all supply-side resource options identified pursuant to section (1) in terms of both of the following cost estimates: utility costs and utility costs plus probable environmental costs. The utility shall indicate which supply-side options are considered to be candidate resource options for purposes of developing the alternative resource plans required by 4 CSR 240-22.060(3). The utility shall also indicate which options are eliminated from further consideration on the basis of the screening analysis and shall explain the reasons for their elimination.

(3) The analysis of supply-side resource options shall include a thorough analysis of existing and planned interconnected genera-

tion resources. The analysis can be performed by the individual utility or in the context of a joint planning study with other area utilities. The purpose of this analysis shall be to ensure that the transmission network is capable of reliably supporting the supply resource options under consideration, that the costs of transmission system investments associated with supply-side resources are properly considered and to provide an adequate foundation of basic information for decisions about the following types of supply-side resource alternatives:

(A) Joint participation in generation construction projects;

(B) Construction of wholly-owned generation or transmission facilities; and

(C) Participation in major refurbishment, upgrading or retrofitting of existing generation or transmission resources.

(4) The utility shall identify and analyze opportunities for life extension and refurbishment of existing generation plants, taking into account their current condition to the extent that it is significant in the planning process.

(5) The utility shall identify and evaluate potential opportunities for new long-term power purchases and sales, both firm and nonfirm, that are likely to be available over all or part of the planning horizon. This evaluation shall be based on an analysis of at least the following attributes of each potential transaction:

(A) Type or nature of the purchase or sale (for example, firm capacity, summer only);

(B) Amount of power to be exchanged;

(C) Estimated contract price;

(D) Timing and duration of the transaction;

(E) Terms and conditions of the transaction, if available;

(F) Required improvements to the utility's generating system, transmission system, or both, and the associated costs; and

(G) Constraints on the utility system caused by wheeling arrangements, whether on the utility's own system, or on an interconnected system, or by the terms and conditions of other contracts or interconnection agreements.

(6) For the utility's preferred resource plan selected pursuant to 4 CSR 240-22.070(7), the utility shall determine if additional future transmission facilities will be required to remedy any new generation-related transmission system inadequacies over the planning horizon. If any such facilities are determined to be required and, in the judgment of utility decision-makers, there is a risk of significant delays or cost increases due to problems in the siting or permitting of any required transmission facilities, this risk shall be analyzed pursuant to the requirements of 4 CSR 240-22.070(2).

(7) The utility shall assess the age, condition and efficiency level of existing transmission and distribution facilities, and shall analyze the feasibility and cost-effectiveness of transmission and distribution system loss-reduction measures as a supply-side resource. This provision shall not be construed to require a detailed line-by-line analysis of the transmission and distribution system, but is intended to require the utility to identify and analyze opportunities for efficiency improvements in a manner that is consistent with the analysis of other supply-side resource options.

(8) Before developing alternative resource plans and performing the integrated resource analysis, the utility shall develop ranges of values and probabilities for several important uncertain factors related to supply resources. These values can also be used to refine or verify information developed pursuant to section (2) of this rule. These cost estimates shall include at least the following elements and shall be based on the indicated methods or sources of information:

(A) Fuel price forecasts over the planning horizon for the appropriate type and grade of primary fuel and for any alternative fuel that may be practical as a contingency option.

1. Fuel price forecasts shall be obtained from a consulting firm with specific expertise in detailed fuel supply and price analysis or developed by the utility if it has expert knowledge and experience with the fuel under consideration. Each forecast shall consider at least the following factors as applicable to each fuel under consideration:

A. Present reserves, discovery rates and usage rates of the fuel and forecasts of future trends of these factors;

B. Profitability and financial condition of producers;

C. Potential effect of environmental factors, competition and government regulations on producers, including the potential for changes in severance taxes;

D. Capacity, profitability and expansion potential of present and potential fuel transportation options;

E. Potential effects of government regulations, competition and environmental legislation on fuel transporters;

F. In the case of uranium fuel, potential effects of competition and government regulations on future costs of enrichment services and cleanup of production facilities; and

G. Potential for governmental restrictions on the use of the fuel for electricity production.

2. The utility shall consider the accuracy of previous forecasts as an important criterion in selecting providers of fuel price forecasts.

3. The provider of each fuel price forecast shall be required to identify the critical uncertain factors that drive the price forecast and to provide a range of forecasts and an associated subjective probability distribution that reflects this uncertainty;

(B) Estimated capital costs including engineering design, construction, testing, startup and certification of new facilities or major upgrades, refurbishment or rehabilitation of existing facilities.

1. Capital cost estimates shall either be obtained from a qualified engineering firm actively engaged in the type of work required or developed by the utility if it has available other sources of expert engineering information applicable to the type of facility under consideration.

2. The provider of the estimate shall be required to identify the critical uncertain factors that may cause the capital cost estimates to change significantly and to provide a range of estimates and an associated subjective probability distribution that reflects this uncertainty;

(C) Estimated annual fixed and variable operation and maintenance costs over the planning horizon for new facilities or for existing facilities that are being upgraded, refurbished or rehabilitated.

1. Fixed and variable operation and maintenance cost estimates shall be obtained from the same source that provides the capital cost estimates.

2. The critical uncertain factors that affect these cost estimates shall be identified and a range of estimates shall be provided, together with an associated subjective probability distribution that reflects this uncertainty;

(D) Forecasts of the annual cost or value of sulfur dioxide emission allowances to be used or produced by each generating facility over the planning horizon.

1. Forecasts of the future value of emission allowances shall be obtained from a qualified consulting firm or other source with expert knowledge of the factors affecting allowance prices.

2. The provider of the forecast shall be required to identify the critical uncertain factors that may cause the value of allowances to change significantly and to provide a range of forecasts and an associated subjective proba-

bility distribution that reflects this uncertainty; and

(E) Annual fixed charges for any facility to be included in rate base or annual payment schedule for leased or rented facilities.

(9) Reporting Requirements. To demonstrate compliance with the provisions of this rule, and pursuant to the requirements of 4 CSR 240-22.080, the utility shall furnish at least the following information:

(A) A summary table showing each supply resource identified pursuant to section (1) and the results of the screening analysis, including:

1. The calculated values of the utility cost and the probable environmental cost for each resource option and the rankings based on these costs;

2. Identification of candidate resource options that may be included in alternative resource plans; and

3. An explanation of the reasons why each supply-side resource option rejected as a result of the screening analysis was not included as a candidate resource option;

(B) A list of the candidate resource options for which the forecasts, estimates and probability distributions described in section (8) have been developed or are scheduled to be developed by the utility's next scheduled compliance filing pursuant to 4 CSR 240-22.080;

(C) A summary of the results of the uncertainty analysis described in section (8) that has been completed for candidate resource options; and

(D) A summary of the mitigation cost estimates developed by the utility for the candidate resource options identified pursuant to subsection (2)(C). This summary shall include a description of how the alternative mitigation levels and associated subjective probabilities were determined and shall identify the source of the cost estimates for the expected mitigation level.

AUTHORITY: sections 386.040, 386.610 and 393.140, RSMo 1986 and 386.250, RSMo Supp. 1991. Original rule filed June 12, 1992, effective May 6, 1993.*

**Original authority: 386.040, RSMo 1939; 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991; 386.610, RSMo 1939; and 393.140, RSMo 1939, amended 1949, 1967.*

4 CSR 240-22.050 Demand-Side Resource Analysis

PURPOSE: This rule specifies the methods by which end-use measures and demand-side programs shall be developed and screened for cost-effectiveness. It also requires the ongoing evaluation of end-use measures and programs, and the use of program evaluation information to improve program design and cost-effectiveness analysis.

(1) Identification of End-Use Measures. The analysis of demand-side resources shall begin with the development of a menu of energy efficiency and energy management measures that provide broad coverage of—

(A) All major customer classes, including at least residential, commercial, industrial and interruptible;

(B) All significant decision-makers, including at least those who choose building design features and thermal integrity levels, equipment and appliance efficiency levels, and utilization levels of the energy-using capital stock;

(C) All major end uses, including at least lighting, refrigeration, space cooling, space heating, water heating and motive power; and

(D) Renewable energy sources and energy technologies that substitute for electricity at the point of use.

(2) Calculation of Avoided Costs. The utility shall develop estimates of the cost savings that can be obtained by substituting demand-side resources for existing and new supply-side resources. These avoided cost estimates, expressed in nominal dollars, shall be used for cost-effectiveness screening and ranking of end-use measures and demand-side programs.

(A) Supply Resource Cost Estimates. The utility shall use the cost estimates developed pursuant to 4 CSR 240-22.040(2) to calculate the following two (2) estimates of avoided cost: avoided utility costs and avoided utility costs plus avoided probable environmental costs.

1. The choice of new generation options used to calculate avoided costs shall be limited to those which will meet the need for capacity under the base-case load forecast at approximately the lowest present value of utility revenue requirements over the planning horizon. The utility shall document the basis on which the timing and choice of the new generation options were determined to be approximately least cost.

2. The utility shall calculate the annual capacity cost of each new generation option and new transmission and distribution facilities as the sum of the levelized capital cost per kilowatt-year and the fixed operation and maintenance cost per kilowatt-year.

3. The utility shall calculate the direct running cost of each generation option as the sum of fuel costs, sulfur dioxide emission allowance costs, and variable operation and maintenance costs per kilowatt-hour (kWh). The probable environmental costs calculated pursuant to 4 CSR 240-22.040(2)(B) shall also be expressed on a per-kilowatt hour basis for both existing and new generation resources.

(B) Avoided Cost Periods. The utility shall determine avoided cost periods by grouping hours on a seasonal (for example, summer, winter and transition) and time-of-use basis (for example, on-peak, off-peak, super-peak or shoulder-peak) as required to adequately reflect significant differences in running costs and the type of capacity being utilized to maintain required reserve margins.

(C) Calculation of Avoided Capacity and Running Costs. Avoided costs shall be calculated as the difference in costs associated with a specified decrement in load large enough to delay the on-line date of the new capacity additions by at least one (1) year.

1. Avoided running cost. For each year of the planning horizon and for each avoided cost period, the utility shall calculate the avoided direct running cost per kWh (including sulfur dioxide emission allowance costs) and the avoided probable environmental running cost per kWh due to the specified load decrement.

2. Avoided capacity costs. The utility shall calculate and document the avoided capacity costs per kilowatt-year for each year of the planning horizon.

A. This calculation shall include the costs of any new generation, transmission and distribution facilities that are delayed or avoided because of the specified load decrement.

B. For each year of the planning horizon, the utility shall determine the avoided cost periods in which the avoided new generation, transmission and distribution capacity was utilized, and shall allocate a nonzero portion of the annualized avoided capacity costs to each of the periods in which that capacity was utilized.

(D) Avoided Demand and Energy Costs. The utility shall use the avoided capacity and running costs (appropriately adjusted to reflect reliability reserve margins, demand losses and energy losses) to calculate the avoided demand and energy costs for each avoided cost period. Demand periods shall be defined as the avoided cost periods in which there is a significant probability of a loss of load (for example, periods which require the use of peaking capacity to maintain power pool reserve margins). Nondemand periods are the avoided cost periods in which there is not a significant probability of a loss of load.

1. Demand period avoided demand costs. Avoided demand costs per kilowatt-year for the demand periods of each season shall include avoided transmission and distribution capacity costs, plus the smaller of the avoided generation capacity cost allocated to the demand period or the avoided capacity cost of peaking capacity.

2. Demand period avoided energy costs. Any capacity cost per kilowatt-year allocated to the demand periods but not included in the avoided demand cost shall be converted to an avoided energy cost by dividing the avoided capacity cost per kilowatt-year by the number of hours in the associated demand period. The utility shall add this converted avoided capacity cost to both of the running cost estimates developed pursuant to paragraph (2)(C)1. to calculate the demand period direct energy costs and the probable environmental energy costs.

3. Nondemand period avoided demand cost. The avoided demand cost for the nondemand periods is zero (0).

4. Nondemand period avoided energy costs. Avoided capacity cost per kilowatt-year allocated to the nondemand periods within each season shall be converted to a per-kilowatt-hour cost by dividing the avoided capacity cost per kilowatt-year by the number of hours in the associated nondemand period. The utility shall add this converted avoided capacity cost to both of the running cost estimates developed pursuant to paragraph (2)(C)1. to calculate the nondemand period direct energy costs and the probable environmental energy costs.

5. Annual avoided demand and energy costs. Annual avoided demand costs shall include avoided transmission and distribution capacity costs, plus the smaller of the annual avoided generation capacity costs or the avoided capacity cost of peaking capacity. Annual avoided energy costs shall include annual avoided running costs plus any avoided capacity costs not included in the annual demand cost.

(3) Cost-Effectiveness Screening of End-Use Measures. The utility shall evaluate the cost-effectiveness of each end-use measure identified pursuant to section (1) using the probable environmental benefits test. All costs and benefits shall be expressed in nominal dollars.

(A) The utility shall develop estimates of the end-use measure demand reduction for each demand period and energy savings per installation for each avoided cost period on a normal-weather basis. If the utility can show that subannual load impact estimates are not required to capture the potential benefits of an end-use measure, annual estimates of demand and energy savings may be used for cost-effectiveness screening.

(B) Benefits per installation of each end-use measure in each avoided cost period shall be calculated as the demand reduction multiplied by the levelized avoided demand cost plus the energy savings multiplied by the levelized avoided energy cost.

1. Avoided costs in each avoided cost period shall be levelized over the planning horizon using the utility discount rate.

2. Annualized benefits shall be calculated as the sum of the levelized benefits over all avoided cost periods.

(C) Annualized costs per installation for each end-use measure shall be calculated as the sum of the following components:

1. Incremental costs of implementing the measure (regardless of who pays these costs) levelized over the life of the measure using the utility discount rate;

2. Incremental annual operation and maintenance costs (regardless of who pays these costs) levelized over the life of the measure using the utility discount rate; and

3. Any probable environmental impact mitigation costs due to implementation of the end-use measure that are borne by either the utility or the customer.

(D) Annualized costs for end-use measures shall not include either utility marketing and delivery costs for demand-side programs or lost revenues due to measure-induced reductions in energy sales or billing demands between rate cases.

(E) Annualized benefits minus annualized costs per installation must be positive or the ratio of annualized benefits to annualized costs must be greater than one (1) for an end-use measure to pass the screening test. The utility may relax this criterion for measures that are judged to have potential benefits which are not captured by the estimated load impacts or avoided costs.

(F) End-use measures that pass the probable environmental benefits test must be included in at least one (1) potential demand-side program.

(G) For each end-use measure that passes the probable environmental benefits test, the utility also shall perform the utility benefits test for informational purposes. This calculation shall include the cost components identified in paragraphs (3)(C)1. and 2..

(4) The utility shall estimate the technical potential of each end-use measure that passes the screening test.

(5) The utility shall conduct market research studies, customer surveys, pilot demand-side programs, test marketing programs and other activities as necessary to estimate the technical potential of end-use measures and to develop the information necessary to design and implement cost-effective demand-side programs. These research activities shall be designed to provide a solid foundation of information about how and by whom energy-related decisions are made and about the most appropriate and cost-effective methods of influencing these decisions in favor of greater long-run energy efficiency.

(6) The utility shall develop a set of potential demand-side programs that are designed to deliver an appropriate selection of end-use measures to each market segment. The demand-side program planning and design process shall include at least the following activities and elements:

(A) Identify market segments that are numerous and diverse enough to provide relatively complete coverage of the classes and decision-makers identified in subsections (1)(A) and (B), and that are specifically defined to reflect the primary market imperfections that are common to the members of the market segment;

(B) Analyze the interactions between end-use measures (for example, more efficient lighting reduces the savings related to efficiency gains in cooling equipment because efficient lighting reduces intrinsic heat gain);

(C) Assemble menus of end-use measures that are appropriate to the shared characteristics of each market segment and cost-effective as measured by the screening test; and

(D) Design a marketing plan and delivery process to present the menu of end-use measures to the members of each market segment and to persuade decision-makers to implement as many of these measures as may be appropriate to their situation.

(7) Cost-Effectiveness Screening of Demand-Side Programs. The utility shall evaluate the cost-effectiveness of each potential demand-side program developed pursuant to section (6) using the total resource cost test. The utility cost test shall also be performed for purposes of comparison. All costs and benefits shall be expressed in nominal dollars. The following procedure shall be used to perform these tests:

(A) The utility shall estimate the incremental and cumulative number of program participants and end-use measure installations due to the program and the incremental and cumulative demand reduction and energy savings due to the program in each avoided cost period in each year of the planning horizon.

1. Initial estimates of demand-side program load impacts shall be based on the best available information from in-house research, vendors, consultants, industry research groups, national laboratories or other credible sources.

2. As the load-impact measurements required by subsection (9)(B) become available, these results shall be used in the ongoing development and screening of demand-side programs and in the development of alternative resource plans;

(B) In each year of the planning horizon, the benefits of each demand-side program shall be calculated as the cumulative demand reduction multiplied by the avoided demand cost plus the cumulative energy savings multiplied by the avoided energy cost, summed over the avoided cost periods within each year. These calculations shall be performed using the avoided probable environmental costs developed pursuant to section (2);

(C) Utility Cost Test. In each year of the planning horizon, the costs of each demand-side program shall be calculated as the sum of all utility incentive payments plus utility costs to administer, deliver and evaluate each demand-side program. For purposes of this test, demand-side program costs shall not include lost revenues or costs paid by participants in demand-side programs;

(D) Total Resource Cost Test. In each year of the planning horizon, the costs of each demand-side program shall be calculated as the sum of all incremental costs of end-use measures that are implemented due to the program (including both utility and participant contributions) plus utility costs to administer, deliver and evaluate each demand-side program. For purposes of this test, demand-side program costs shall not include lost revenues or utility incentive payments to customers;

(E) The present value of program benefits minus the present value of program costs over the planning horizon must be positive or the ratio of annualized benefits to annualized costs must be greater than one (1) for a demand-side program to pass the utility cost test or the total resource cost test. The utility may relax this criterion for programs that are judged to have potential benefits that are not captured by the estimated load impacts or avoided costs; and

(F) Potential demand-side programs that pass the total resource cost test shall be considered as candidate resource options and must be included in at least one (1) alternative resource plan developed pursuant to 4 CSR 240-22.060(3).

(8) For each demand-side program that passes the total resource cost test, the utility shall develop time-differentiated load impact estimates over the planning horizon at the level of detail required by the supply system simulation model that is used in the integrated resource analysis required by 4 CSR 240-22.060(4).

(9) Evaluation of Demand-Side Programs. The utility shall develop evaluation plans for all demand-side programs that are included in the preferred resource plan selected pursuant to 4 CSR 240-22.070(6). The purpose of these evaluations shall be to develop the information necessary to improve the design of existing and future demand-side programs, and to gather data on the implementation costs and load impacts of programs for use in cost-effectiveness screening and integrated resource analysis.

(A) Process Evaluation. Each demand-side program that is part of the utility's preferred resource plan shall be subjected to an ongoing evaluation process which addresses at least the following questions about program design:

1. What are the primary market imperfections that are common to the target market segment?

2. Is the target market segment appropriately defined or should it be further subdivided or merged with other segments?

3. Does the mix of end-use measures included in the program appropriately reflect the diversity of end-use energy service needs and existing end-use technologies within the target segment?

4. Are the communication channels and delivery mechanisms appropriate for the target segment? and

5. What can be done to more effectively overcome the identified market imperfections and to increase the rate of customer acceptance and implementation of each end-use measure included in the program?

(B) Impact Evaluation. The utility shall develop methods of estimating the actual load impacts of each demand-side program included in the utility's preferred resource plan to a reasonable degree of accuracy.

1. Impact evaluation methods. Comparisons of one (1) or both of the following types shall be used to measure program impacts in a manner that is based on sound statistical principles:

A. Comparisons of preadoption and postadoption loads of program participants, corrected for the effects of weather and other intertemporal differences; and

B. Comparisons between program participants' loads and those of an appropriate control group over the same time period.

2. The utility shall develop load-impact measurement protocols that are designed to make the most cost-effective use of the following types of measurements, either individually or in combination: monthly billing data, load research data, end-use load metered data, building and equipment simulation models, and survey responses or audit data on appliance and equipment type, size and efficiency levels, household or business characteristics, or energy-related building characteristics.

(C) The utility shall develop protocols to collect data regarding demand-side program market potential, participation rates, utility costs, participant costs and total costs.

(10) Demand-side programs and load-building programs shall be separately designed and administered, and all costs shall be separately classified so as to permit a clear distinction between demand-side program costs and the costs of load-building programs. The costs of demand-side resource development that also serve other functions shall be allocated between the functions served.

(11) Reporting Requirements. To demonstrate compliance with the provisions of this rule, and pursuant to the requirements of 4 CSR 240-22.080, the utility shall prepare a report that contains at least the following information:

(A) A list of the end-use measures developed for initial screening pursuant to the requirements of section (1) of this rule;

(B) The estimated load impacts, annualized costs per installation and the results of the probable environmental benefits test for each end-use measure identified pursuant to section (1);

(C) The technical potential and the results of the utility benefits test for each end-use measure that passes the probable environmental benefits test;

(D) Documentation of the methods and assumptions used to develop the avoided cost estimates developed pursuant to section (2) including:

1. A description of the type and timing of new supply resources, including transmission and distribution facilities, used to calculate avoided capacity costs;

2. A description of the assumptions and procedure used to calculate avoided running costs;

3. A description of the avoided cost periods and how they were determined;

4. A tabulation of the direct running costs and the probable environmental running costs for each avoided cost period in each year of the planning horizon; and

5. A tabulation of the avoided demand cost, the avoided direct energy costs and the avoided probable environmental energy costs for each avoided cost period in each year of the planning horizon;

(E) Copies of completed market research studies, pilot programs, test marketing programs and other studies as required by section (5) of this rule and descriptions of those studies that are planned or in progress and the scheduled completion dates;

(F) A description of each market segment identified pursuant to subsection (6)(A);

(G) A description of each demand-side program developed for initial screening pursuant to section (6) of this rule;

(H) A tabulation of the incremental and cumulative number of participants, load impacts, utility costs and program participant costs in each year of the planning horizon for each demand-side program developed pursuant to section (6) of this rule;

(I) The results of the utility cost test and the total resource cost test for each demand-side program developed pursuant to section (6) of this rule; and

(J) A description of the process and impact evaluation plans for demand-side programs that are included in the preferred resource plan as required by section (9) of this rule and the results of any such evaluations that have been completed since the utility's last scheduled filing pursuant to 4 CSR 240-22.080.

AUTHORITY: sections 386.040, 386.610 and 393.140, RSMo 1986 and 386.250, RSMo Supp. 1991. Original rule filed June 12, 1992, effective May 6, 1993.*

**Original authority: 386.040, RSMo 1939; 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991; 386.610, RSMo 1939; and 393.140, RSMo 1939, amended 1949, 1967.*

4 CSR 240-22.060 Integrated Resource Analysis

PURPOSE: This rule requires the utility to design alternative resource plans to meet the planning objectives identified in 4 CSR 240-22.010(2) and sets minimum standards for the scope and level of detail required in resource plan analysis, and for the logically consistent and economically equivalent analysis of alternative resource plans.

(1) Resource Planning Objectives. The utility shall design alternative resource plans to satisfy at least the objectives and priorities identified in 4 CSR 240-22.010(2). The utility may identify additional planning objectives that alternative resource plans will be designed to serve.

(2) Specification of Performance Measures. The utility shall specify a set of quantitative measures for assessing the performance of alternative resource plans with respect to identified planning objectives. These measures shall include at least the following: present worth of utility revenue requirements, present worth of probable environmental costs, present worth of out-of-pocket costs to participants in demand-side programs, levelized annual average rates and maximum single-year increase in annual average rates. All present worth and levelization calculations shall use the utility discount rate and all costs and benefits shall be expressed in nominal dollars. Utility decision-makers may also specify other measures that they believe are appropriate for assessing the performance of resource plans relative to the planning objectives identified in 4 CSR 240-22.010(2).

(3) Development of Alternative Resource Plans. The utility shall use appropriate combinations of candidate demand-side and supply-side resources to develop a set of alternative resource plans, each of which is designed to achieve one (1) or more of the planning objectives identified in 4 CSR 240-22.010(2). The alternative resource plans developed at this stage of the analysis shall not include load-building programs, which shall be analyzed as required by section (5) of this rule.

(4) Analysis of Alternative Resource Plans. The utility shall assess the relative performance of the alternative resource plans by calculating for each plan the value of each performance measure specified pursuant to section (2). This calculation shall assume values for uncertain factors that are judged by utility decision-makers to be most likely. The analysis shall cover a planning horizon of at least twenty (20) years and shall be carried out with computer models that are capable of simulating the total operation of the system on a year-by-year basis in order to assess the cumulative impacts of alternative resource plans. These models shall be sufficiently detailed to accomplish the following tasks and objectives:

(A) The financial impact of alternative resource plans shall be modeled in sufficient detail to provide comparative estimates of at least the following measures of the utility's financial condition for each year of the planning horizon: pretax interest coverage, ratio of total debt to total capital and ratio of net cash flow to capital expenditures;

(B) The modeling procedure shall be based on the assumption that rates will be adjusted annually, in a manner that is consistent with Missouri law. This provision does not imply any requirement for the utility to file actual rate cases or for the commission to accord any particular ratemaking treatment to actual costs incurred by the utility;

(C) The modeling procedure shall include a method to ensure that the impact of changes in electric rates on future levels of demand for electric service is accounted for in the analysis; and

(D) The modeling procedure shall treat supply-side and demand-side resources on a logically consistent and economically equivalent basis. This means that the same types or categories of costs, benefits and risks shall be considered, and that these factors shall be quantified at a similar level of detail and precision for all resource types.

(5) Analysis of Load-Building Programs. If the utility intends to continue existing load-building programs or implement new ones, it shall analyze these programs in the context of one (1) or more of the alternative plans developed pursuant to section (3) of this rule, including the preferred resource plan selected pursuant to 4 CSR 240-22.070(6). This analysis shall use the same modeling procedure and assumptions described in section (4) and shall include the following elements:

(A) Estimation of the impact of load-building programs on the electric utility's summer and winter peak demands and energy usage;

(B) A comparison of annual average rates in each year of the planning horizon for the resource plan with and without the load-building program;

(C) A comparison of the probable environmental costs of the resource plan in each year of the planning horizon with and without the proposed load-building program; and

(D) An assessment of any other aspects of the proposed load-building programs that affect the public interest.

(6) Reporting Requirements. To demonstrate compliance with the provisions of this rule, and pursuant to the requirements of 4 CSR 240-22.080, the utility shall prepare a report that contains at least the following information:

(A) A description of each alternative resource plan including the type and size of each resource addition and a listing of the sequence and schedule for retiring existing resources and acquiring each new resource addition;

(B) A summary tabulation that shows the performance of each alternative resource plan as measured by each of the measures specified in section (2) of this rule;

(C) For each alternative resource plan, a plot of each of the following over the planning horizon:

1. The combined impact of all demand-side resources on the base-case forecast of summer and winter peak demands;
2. The composition, by program, of the capacity provided by demand-side resources;
3. The composition, by supply resource, of the capacity (including reserve margin) provided by supply resources. Existing supply-side resources may be shown as a single resource;
4. The combined impact of all demand-side resources on the base-case forecast of annual energy requirements;
5. The composition, by program, of the annual energy provided by demand-side resources;
6. The composition, by supply resource, of the annual energy (including losses) provided by supply resources. Existing supply-side resources may be shown as a single resource;
7. The values of the three (3) measures of financial condition identified in subsection (4)(A);
8. Annual average rates;
9. Annual emissions of each environmental pollutant identified pursuant to 4 CSR 240-22.040(2)(B)1; and
10. Annual probable environmental costs.

(D) A discussion of how the impacts of rate changes on future electric loads were modeled and how the appropriate estimates of price elasticity were obtained;

(E) A description of the computer models used in the analysis of alternative resource plans; and

(F) A description of any proposed load-building programs, a discussion of why these programs are judged to be in the public interest and, for all resource plans that include these programs, plots of the following over the planning horizon:

1. Annual average rates with and without the load-building programs; and
2. Annual utility costs and probable environmental costs with and without the load-building programs.

AUTHORITY: sections 386.040, 386.610 and 393.140, RSMo 1986 and 386.250, RSMo Supp. 1991. Original rule filed June 12, 1992, effective May 6, 1993.*

**Original authority: 386.040, RSMo 1939; 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991; 386.610, RSMo 1939; and 393.140, RSMo 1939, amended 1949, 1967.*

4 CSR 240-22.070 Risk Analysis and Strategy Selection

PURPOSE: This rule requires the utility to identify the critical uncertain factors that affect the performance of resource plans, establishes minimum standards for the methods used to assess the risks associated with these uncertainties and requires the utility to specify and officially adopt a resource acquisition strategy.

(1) The utility shall use the methods of formal decision analysis to assess the impacts of critical uncertain factors on the expected performance of each of the alternative resource plans developed pursuant to 4 CSR 240-22.060(3), to analyze the risks associated with alternative resource plans, to quantify the value of better information concerning the critical uncertain factors and to explicitly state and document the subjective probabilities that utility decision-makers assign to each of these uncertain factors. This assessment shall include a decision-tree representation of the key decisions and uncertainties associated with each alternative resource plan.

(2) Before developing a detailed decision-tree representation of each resource plan, the utility shall conduct a preliminary sensitivity analysis to identify the uncertain factors that are critical to the performance of the resource plan. This analysis shall assess at least the following uncertain factors:

(A) The range of future load growth represented by the low-case and high-case load forecasts;

(B) Future interest rate levels and other credit market conditions that can affect the utility's cost of capital;

(C) Future changes in environmental laws, regulations or standards;

(D) Relative real fuel prices;

(E) Siting and permitting costs and schedules for new generation and generation-related transmission facilities;

(F) Construction costs and schedules for new generation and transmission facilities;

(G) Purchased power availability, terms and cost;

(H) Sulfur dioxide emission allowance prices;

(I) Fixed operation and maintenance costs for existing generation facilities;

(J) Equivalent or full- and partial-forced-outage rates for new and existing generation facilities;

(K) Future load impacts of demand-side programs; and

(L) Utility marketing and delivery costs for demand-side programs.

(3) For each alternative resource plan, the utility shall construct a decision-tree diagram that appropriately represents the key resource decisions and critical uncertain factors that affect the performance of the resource plan.

(4) The decision-tree diagram for all alternative resource plans shall include at least two (2) chance nodes for load growth uncertainty over consecutive subintervals of the planning horizon. The first of these subintervals shall be not more than ten (10) years long.

(5) The utility shall use the decision-tree formulation to compute the cumulative probability distribution of the values of each performance measure specified pursuant to 4 CSR 240-22.060(2), contingent upon the identified uncertain factors and associated subjective probabilities assigned by utility decision-makers pursuant to section (1) of this rule. Both the expected performance and the risks of each alternative resource plan shall be quantified.

(A) The expected performance of each resource plan shall be measured by the statistical expectation of the value of each performance measure.

(B) The risk associated with each resource plan shall be characterized by some measure of the dispersion of the probability distribution for each performance measure, such as the standard deviation or the values associated with specified percentiles of the distribution.

(6) The utility shall select a preferred resource plan from among the alternative plans that have been analyzed pursuant to the requirements of 4 CSR 240-22.060 and sections (1)–(5) of this rule. The preferred resource plan shall satisfy at least the following conditions:

(A) In the judgment of utility decision-makers, the preferred plan shall strike an appropriate balance between the various planning objectives specified in 4 CSR 240-22.010(2); and

(B) The trend of expected unserved hours for the preferred resource plan must not indicate a consistent increase in the need for emergency imported power over the planning horizon.

(7) The impact of the preferred resource plan on future requirements for emergency imported power shall be explicitly modeled and quantified. The requirement for emergency

imported power shall be measured by expected unserved hours under normal-weather load conditions.

(A) The daily normal-weather series used to develop normal-weather loads shall contain a representative amount of day-to-day temperature variation. Both the high and low extreme values of daily normal-weather variables shall be consistent with the historical average of annual extreme temperatures.

(B) The supply-system simulation software used to calculate expected unserved hours shall be capable of accurately representing at least the following aspects of system operations:

1. Chronological dispatch, including unit commitment decisions that are consistent with the operational characteristics and constraints of all system resources;

2. Heat rates, fuel costs, variable operation and maintenance costs, and sulfur dioxide emission allowance costs for each generating unit;

3. Scheduled maintenance outages for each generating unit;

4. Partial- and full-forced-outage rates for each generating unit; and

5. Capacity and energy purchases and sales, including the full spectrum of possibilities, from long-term firm contracts or unit participation agreements to hourly economy transactions.

A. The utility shall maintain the capability to model purchases and sales of energy both with and without the inclusion of sulfur dioxide emission allowances.

B. The level of energy sales and purchases shall be consistent with forecasts of the utility's own production costs as compared to the forecasted production costs of other likely participants in the bulk power market; and

(C) The utility may use an alternative method of calculating expected unserved hours per year if it can demonstrate that the alternative method produces results that are equivalent to those obtained by a method that meets the requirements of subsection (7)(B).

(8) The utility shall quantify the expected value of better information concerning at least the critical uncertain factors that affect the performance of the preferred resource plan, as measured by the present value of utility revenue requirements.

(9) The utility shall develop an implementation plan that specifies the major tasks and schedules necessary to implement the preferred resource plan over the implementation period. The implementation plan shall contain:

(A) A schedule and description of ongoing and planned research activities to update and improve the quality of data used in load analysis and forecasting;

(B) A schedule and description of ongoing and planned demand-side programs, program evaluations and research activities;

(C) A schedule and description of all supply-side resource acquisition and construction activities; and

(D) Identification of critical paths and major milestones for each resource acquisition project, including decision points for committing to major expenditures.

(10) The utility shall develop, document and officially adopt a resource acquisition strategy. This means that the utility's resource acquisition strategy shall be formally approved by the board of directors, a committee of senior management, an officer of the company or other responsible party who has been duly delegated the authority to commit the utility to the course of action described in the resource acquisition strategy. The officially adopted resource acquisition strategy shall consist of the following components:

(A) A preferred resource plan selected pursuant to the requirements of section (6) of this rule;

(B) An implementation plan developed pursuant to the requirements of section (9) of this rule;

(C) A specification of the ranges or combinations of outcomes for the critical uncertain factors that define the limits within which the preferred resource plan is judged to be appropriate and an explanation of how these limits were determined;

(D) A set of contingency options that are judged to be appropriate responses to extreme outcomes of the critical uncertain factors and an explanation of why these options are judged to be appropriate responses to the specified outcomes; and

(E) A process for monitoring the critical uncertain factors on a continuous basis and reporting significant changes in a timely fashion to those managers or officers who have the authority to direct the implementation of contingency options when the specified limits for uncertain factors are exceeded.

(11) Reporting Requirements. To demonstrate compliance with the provisions of this rule, and pursuant to the requirements of 4 CSR 240-22.080, the utility shall furnish at least the following information:

(A) A decision-tree diagram for each of the alternative resource plans along with narrative discussions of the following aspects of the decision analysis:

1. A discussion of the sequence and timing of the decisions represented by decision nodes in the decision tree and a description of the specific decision alternatives considered at each decision point; and

2. An explanation of how the critical uncertain factors were identified, how the ranges of potential outcomes for each uncertain factor were determined and how the subjective probabilities for each outcome were derived;

(B) Plots of the cumulative probability distribution of each performance measure for each alternative resource plan;

(C) For each performance measure, a table that shows the expected value and the risk of each resource plan;

(D) A plot of the expected level of annual unserved hours for the preferred resource plan over the planning horizon;

(E) A discussion of the analysis of the value of better information required by section (8), a tabulation of the key quantitative results of that analysis and a discussion of how those findings will be incorporated in ongoing research activities;

(F) A discussion of the process used to select the preferred resource plan, including the relative weights given to the various performance measures and the rationale used by utility decision-makers to judge the appropriate tradeoffs between competing planning objectives and between expected performance and risk; and

(G) The fully documented resource acquisition strategy that has been developed and officially adopted pursuant to the requirements of section (10) of this rule.

AUTHORITY: sections 386.040, 386.610 and 393.140, RSMo 1986 and 386.250, RSMo Supp. 1991. Original rule filed June 12, 1992, effective May 6, 1993.*

**Original authority: 386.040, RSMo 1939; 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991; 386.610, RSMo 1939; and 393.140, RSMo 1939, amended 1949, 1967.*

4 CSR 240-22.080 Filing Schedule and Requirements

PURPOSE: This rule specifies the requirements for electric utility filings to demonstrate compliance with the provisions of this chapter. The purpose of the compliance review required by this chapter is not commission approval of the substantive findings, determinations or analyses contained in the filing. The purpose of the compliance review required by this chapter is to determine *whether the utility's resource acquisition strategy meets the requirements stated in 4 CSR 240-22.010(2)(A)–(C).*

(1) Each electric utility which sold more than one (1) million megawatt-hours to Missouri retail electric customers for calendar year 1991 shall make a filing with the commission every three (3) years that demonstrates compliance with the provisions of this chapter. The utility's filing shall include at least the following items:

(A) Letter of transmittal;

(B) Summary information and any press release related to the filing;

(C) Reports and information required by 4 CSR 240-22.030(8), 4 CSR 240-22.040(9), 4 CSR 240-22.050(11), 4 CSR 240-22.060(6) and 4 CSR 240-22.070(11);

(D) A narrative description and summary of the reports and information referred to in subsection (1)(C). The narrative shall specifically show that the resource acquisition strategy contained in the filing has been officially approved by the utility and that the methods used and the procedures followed by the utility in formulating the resource acquisition strategy comply with the provisions of this chapter;

(E) A request for a protective order from the commission if the utility seeks to protect anything contained in the filing as trade secrets, or as confidential or private technical, financial or business information; and

(F) Tariff sheets as required by 4 CSR 240-14.040(2) for demand-side programs that are promotional practices as defined by 4 CSR 240-14.010(6)(L).

(2) The electric utility's compliance filing may also include a request for nontraditional accounting procedures and information regarding any associated ratemaking treatment to be sought by the utility for demand-side resource costs. If the utility desires to make any such request, it must be made in the utility's compliance filing pursuant to this rule and not at some subsequent time. If the utility desires to continue any previously authorized nontraditional accounting procedures beyond the three (3)-year implementation period, it must request reauthorization in each subsequent filing pursuant to this rule. Any request for initial authorization or reauthorization of these nontraditional accounting procedures must—

(A) Be limited to specific demand-side programs that are included in the utility's implementation plan; and

(B) Include specific proposals that contain at least the following information:

1. An explanation of the specific form and mechanics of implementing the proposed accounting procedure and any associated ratemaking treatment to be sought;

2. A discussion of the rationale and justification of the need for a nontraditional treatment of these costs;

3. An explanation of how the specific proposal meets this need for nontraditional treatment; and

4. A quantitative comparison of the utility's estimated earnings over the three (3)-year implementation period with and without the proposed nontraditional accounting procedures and any associated ratemaking treatment to be sought.

(3) The electric utilities shall make their initial compliance filings on a staggered basis in order of decreasing size of gross annual Missouri operating revenues from retail electric sales for calendar year 1991. The electric utility with the largest gross annual Missouri operating revenues shall make its initial filing seven (7) months (December 1993) after the effective date of this chapter (May 5, 1993). The remaining electric utilities shall make their initial filings in successive increments of seven (7) months from the effective date of this chapter (May 5, 1993).

(4) The commission will establish a docket for the purpose of receiving the compliance filing of each affected electric utility. The commission will issue an order that establishes an intervention deadline, sets an early prehearing conference and provides for notice.

(5) The staff shall review each compliance filing required by this rule and shall file a report not later than one hundred twenty (120) days after each utility's scheduled filing date that identifies any deficiencies in the electric utility's compliance with the provisions of this chapter, any major deficiencies in the methodologies or analyses required to be performed by this chapter and any other deficiencies which, in its limited review, the staff determines would cause the electric utility's resource acquisition strategy to fail to meet the requirements identified in 4 CSR 240-22.010(2)(A)–(C). If the staff's limited review finds no deficiencies, the staff shall state that in the report. A staff report that finds that an electric utility's filing is in compliance with this chapter shall not be construed as acceptance or agreement with the substantive findings, determinations or analysis contained in the electric utility's filing.

(6) Also within one hundred twenty (120) days after an electric utility's compliance filing pursuant to this rule, the office of public counsel and any intervenor may file a report or comments based on a limited review that identify any deficiencies in the electric utility's compliance with the provisions of this chapter, any deficiencies in the methodologies or analyses required to be performed by this chapter, and any other deficiencies which the public counsel or intervenor believes would cause the utility's resource acquisition strategy to fail to meet the requirements identified in 4 CSR 240-22.010(2)(A)–(C).

(7) All workpapers, documents, reports, data, computer model documentation, analysis, letters, memoranda, notes, test results, studies, recordings, transcriptions and any other supporting information relating to the filed resource acquisition strategy within the electric utility's or its contractors' possession, custody or control shall be preserved and made available in accordance with any protective order to the staff, public counsel and any intervenor for use in its review of the periodic filings required by this rule. Each electric utility shall retain at least one (1) copy of the officially adopted resource acquisition strategy and all supporting information for at least ten (10) years.

(8) If the staff, public counsel or any intervenor finds deficiencies, it shall work with the electric utility and the other parties to reach, within forty-five (45) days of the date that the report or comments were submitted, a joint agreement on a plan to remedy the identified deficiencies. If full agreement cannot be reached, this should be reported to the commission through a joint filing as soon as possible, but no later than forty-five (45) days after the date on which the report or comments were submitted. The joint filing should set out in a brief narrative description those areas on which agreement cannot be reached.

(9) If full agreement on remedying deficiencies is not reached, then within sixty (60) days from the date on which the staff, public counsel or any intervenor submitted a report or comments relating to the electric utility's compliance filing, the electric utility may file a response and the staff, public counsel and any intervenor may file comments in response to each other. The commission will issue an order which indicates on what items, if any, a hearing will be held and which establishes a procedural schedule.

(10) If the utility determines that circumstances have changed so that the preferred resource plan is no longer appropriate, either due to the limits identified pursuant to 4 CSR 240-22.070(10)(C) being exceeded or for

other reasons, the utility, in writing, shall notify the commission within sixty (60) days of the utility's determination. If the utility decides to implement any of the contingency options identified pursuant to 4 CSR 240-22.070(10)(D), the utility shall file for review in advance of its next regularly scheduled compliance filing a revised implementation plan.

(11) Upon written application, and after notice and an opportunity for hearing, the commission may waive or grant a variance from a provision of this chapter for good cause shown.

(A) The granting of a variance to one (1) electric utility which waives or otherwise affects the required compliance with a provision of this chapter does not constitute a waiver respecting, or otherwise affect, the required compliance of any other electric utility with a provision of these rules.

(B) The commission will not waive or grant a variance from this chapter in total.

(12) The commission may extend or reduce any of the time periods specified in this rule for good cause shown.

(13) The commission will issue an order which contains findings that the electric utility's filing pursuant to this rule either does or does not demonstrate compliance with the requirements of this chapter, and that the utility's resource acquisition strategy either does or does not meet the requirements stated in 4 CSR 240-22.010(2)(A)–(C), and which addresses any utility requests pursuant to section (2) for authorization or reauthorization of nontraditional accounting procedures for demand-side resource costs.

AUTHORITY: sections 386.040, 386.610 and 393.140, RSMo 1986 and 386.250, RSMo Supp. 1991. Original rule filed June 12, 1992, effective May 6, 1993.*

**Original authority: 386.040, RSMo 1939; 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991; 386.610, RSMo 1939; and 393.140, RSMo 1939, amended 1949, 1967.*

MEMORANDUM

TO: EPAct 2005 Sections 1251, 1252 and 1254 - New Section 111(d)(11), (12), (13), (14) and (15) Public Utility Regulatory Policies Act (PURPA) Standards

FROM: Steven Dottheim

DATE: March 17, 2006

SUBJECT: **History Of Section 111(d) PURPA Electric and Gas Proceedings At MoPSC**

I. Energy Policy Act (EPAct) 2005

A. Sections 1251, 1252 and 1254 - New Section 111(d) PURPA Standards

The newest PURPA Section 111(d) standards, i.e., from Sections 1251, 1252 and 1254 of EPAct 2005, are as follows:

Sec. 111(d)(11) Net Metering (Section 1251 of EPAct 2005)
Sec. 111(d)(12) Fuel Sources (Section 1251 of EPAct 2005)
Sec. 111(d)(13) Fossil Fuel Generation Efficiency (Section 1251 of EPAct 2005)
Sec. 111(d)(14) Time-Based Metering and Communications (Section 1252 of EPAct 2005)
Sec. 111(d)(15) Interconnection (Section 1254 of EPAct 2005)

II. Public Utility Regulatory Policies Act of 1978 (PURPA)

A. Electric Section 111(d) Standards of PURPA

The original Public Utility Regulatory Policies Act (PURPA) Section 111(d) standards, i.e., provisions from the 1978 federal legislation, were as follows:

Sec. 111 Consideration And Determination Respecting Certain Ratemaking Standards - (a) Consideration and Determination.--Each State regulatory authority (with respect to each electric utility for which it has rate-making authority) . . . shall consider each standard established by subsection (d) and make a determination concerning whether or not it is appropriate to implement such standard to carry out the purposes of this title. . . . Nothing in this subsection prohibits any State regulatory authority or nonregulated electric utility from making any determination that it is not appropriate to implement any such standard, pursuant to its authority under otherwise applicable State law.

Sec. 111(d)(1) Cost Of Service
Sec. 111(d)(2) Declining Block Rates
Sec. 111(d)(3) Time-Of-Day Rates

Sec. 111(d)(4) Seasonal Rates
Sec. 111(d)(5) Interruptible Rates
Sec. 111(d)(6) Load Management Techniques

The Missouri Public Service Commission (Commission) did adopt rules as a result of PURPA, but the rules did not relate to the Section 111(d) standards. The Commission addressed the Section 111(d) standards in rate design or ratemaking cases.

For Union Electric Company (UE) and Kansas City Power & Light Company (KCPL), the Commission addressed the Section 111(d) standards in pending comprehensive class cost of service / rate design cases, Case No. EO-78-163 for UE and Case No. EO-78-161 for KCPL.

Respecting UE, Case No. EO-78-163 settled after going to hearing. *Re Union Electric Company*, Case No. EO-78-163, Report And Order, 23 Mo.P.S.C.(N.S.) 429 (1979). On February 15, 1980, a stipulation and agreement executed by all parties, except the City of St. Louis and St. Louis County, was filed with the Commission. The stipulation and agreement states as follows regarding the PURPA Section 111(d) standards, 23 Mo.P.S.C.(N.S.) at 436:

> 14. The rates established herein are in conformance with the first five ratemaking standards established in Section 111(d) of the Public Utility Regulatory Policies Act, to the extent that such standards are at the present time considered appropriate to carry out the purposes of the Act; and the proceedings herein comply with and satisfy the requirements of Sections 111 and 112 of PURPA with respect to such standards.

The Commission concluded as follows in its Report And Order adopting the stipulation and agreement: "The Commission is also of the opinion that the rates prescribed therein are in conformance with the first five (5) ratemaking standards established in Section 111(d) of the Public Utility Regulatory Policies Act (PURPA) and the proceedings in this case satisfy the requirements of Sections 111 and 112 of PURPA in respect to such standards." 23 Mo.P.S.C.(N.S.) at 437.

Respecting KCPL, on February 7, 1980, the Commission directed that the first five ratemaking standards contained in Section 111(d) be considered in the context of Case No. EO-78-163. *Re Kansas City Power & Light Company*, Case No. EO-78-161, Report And Order, 25 Mo.P.S.C.(N.S.) 605, 608 (1983). Case No. EO-78-163 did not settle, but went to hearing and was fully briefed. The Commission held in its Report And Order that the record in the case was inadequate for it to make the required determinations and therefore "said standards . . . shall be considered by the Commission in KCPL's pending rate case, Case Nos. ER-83-49, ER-83-72 and EO-82-65." 25 Mo.P.S.C.(N.S.) at 610. "Ordered: 7." of the Commission's Report And Order states: "Ordered 7: That the six PURPA ratemaking standards [16 U.S.C. 2621(d)(1)-(6)] shall be considered by the Commission in Kansas City Power & Light Company's pending rate case, Case Nos. ER-83-49, ER-83-72 and EO-82-65." 25 Mo.P.S.C.(N.S.) at 632.

The Commission adopted the PURPA Section 111(d) standards in Case No. ER-83-49, et al., as follows:

> *Ordered*: 13. That Standards 1-4 found in Section 111(d) of the Public Utility Regulatory Act of 1978, 16 U.S.C. Section 2601, et seq., be, and are, hereby adopted as ratemaking standards to be employed by this Commission in considering any future ratemaking application or proceeding involving Kansas City Power & Light Company.
>
> *Ordered*: 14. That in order to complete the consideration of the PURPA Load Management Techniques Standard, Kansas City Power & Light Company be, and is, hereby directed to file with the Commission, in a separate docket, but in any event no later than the filing of testimony in its next general rate case, its proposal or a plan for implementing the PURPA Load Management Techniques Standard.
>
> *Ordered*: 15. The following Standard is hereby adopted as a substitute for the Interruptible Rates Standard contained in Section 1(d) of PURPA:
>
>> *Interruptible Rates Standard* – Each electric utility shall offer each industrial and commercial electric consumer an interruptible rate which reflects the cost of providing interruptible service, if it is determined that the long-run benefits of such rate to the electric utility and its electric consumers are likely to exceed the costs associated with the use of such rates including, but not limited to, metering costs.

Respecting Missouri Public Service Company (MPS), the Commission issued an Order in Case No. ER-83-40 on February 4, 1983 stating that it would consider the six ratemaking standards found in Section 111(d) of PURPA to determine whether it is appropriate to implement such standards in order to meet the purposes of PURPA. *Re Missouri Public Service Company*, Case No. ER-83-40, Report And Order, 26 Mo.P.S.C.(N.S.) 82 (1983). The Commission ordered MPS to publish in a newspaper of general circulation notice of the Commission's decision to consider the ratemaking standards in the context of that case and further requiring the Staff, MPS and any other interested party to file evidence. 26 Mo.P.S.C.(N.S.) at 83-84. The Staff, MPS and Public Counsel recommended adoption of the Section 111(d) (1), (2), (3), (4) and (6) standards, but also recommended that the Section 111(d) (5) standard should not be adopted. The Staff proposed that in lieu of the Section 111(d) (5) Interruptible Rates standard, the Commission should adopt language proposed by the Staff. Regarding the 111(d)(6) Load Management Techniques standard, the Staff, MPS and Public Counsel agreed that should the Commission adopt that standard, a separate docket should be established to analyze the results of the load study being conducted of MPS's system. *Id.* at 101-02.

The Commission (i) adopted the Section 111(d)(1), (2), (3), (4) and (6) standards, as agreed to by the Staff, MPS and Public Counsel; (ii) rejected the Section 111(d)(5) standard on Interruptible Rates, as sought by the Staff; and (iii) adopted the language proposed by the Staff as its policy regarding Interruptible Rates. The Commission directed MPS to propose specific load management techniques in its pending rate design case or in its next general rate case. 26 Mo.PSC.(N.S.) at 102, 104.

Respecting Empire District Electric Company (Empire), as a result of the prehearing conference in Case No. ER-82-40, the parties stipulated and agreed, in part, as follows:

> 13.
>
> That the rates established herein are in conformance with the first five ratemaking standards established in Section 111(d) of the Public Utility Regulatory Policies Act, to the extent that such standards are at the present time considered appropriate to carry out the purposes of the Act; and that proceedings herein comply with and satisfy the requirements of Sections 111 and 112 of PURPA with respect to such standards.

Re Empire District Electric Company, Case No. EO-82-40, Report And Order, 25 Mo.P.S.C.(N.S.) 568, 575 (1983). The Commission stated in its Report And Order:

> . . . the Commission, by this report and order, specifically adopts the first five ratemaking standards established in Section 111(d) of the Public Utility Regulatory Policies Act to the extent that such standards are, in the context of this case at this time, considered appropriate to carry out the purposes of the Act.

25 Mo.P.S.C.(N.S.) at 576.

To date, I have not been able to identify the case(s) in which the Commission considered the Section 111(d) (1)-(6) standards for St. Joseph Light & Power Company.

B. Electric Sections 113, 115, 201 and 210 of PURPA 1978

The Commission adopted 4 CSR 240-20.050 Individual Electric Meters – When Required in compliance with Section 113(b)(1) and Section 115(d) of PURPA. The Commission also adopted 4 CSR 240-20.060 Cogeneration pursuant to Section 201 and Section 210 of PURPA. Section 113 provides in part as follows:

> Sec. 113 (a) Adoption Of Standards.-- . . . Nothing in this subsection prohibits any State regulatory authority or nonregulated electric utility from making any determination that it is not appropriate to adopt any such standard, pursuant to its authority under otherwise applicable State law.
>
> Sec. 113(b)(1) Master Metering.
> Sec. 113(b)(2) Automatic Adjustment Clauses.
> Sec. 113(b)(3) Information To Consumers.
> Sec. 113(b)(4) Procedures For Termination Of Electric Service.
> Sec. 113(b)(5) Advertising.

Section 210 provides in part as follows:

Sec. 210. Cogeneration and Small Power Production.

(a) Cogeneration and Small Power Production Rules.-- . . . the Commission shall prescribe, and from time to time thereafter revise, such rules as it determines necessary to encourage cogeneration and small power production . . .

C. Gas Section 303(b) of PURPA 1978

Title III of the original enactment of PURPA in 1978 addressed retail policies for natural gas utilities and adopted certain standards which as in the instance of electric standards the state commissions were required to consider but not to adopt if the state commission determined that it was not appropriate to do so. The Section 303(b) standards were (1) Procedures For Termination Of Natural Gas Service and (2) Advertising. Although this section of PURPA is not necessarily relevant to the task that EPAct Team 2005 has been charged with, it is relevant to the historical background regarding gas resource planning which is addressed near to the end of this memorandum.

III. Energy Policy Act 1992 (EPAct 1992)

A. Electric Sections 111 and 712 of EPAct 1992 – New Section 111(d) PURPA Standards

The next PURPA Section 111(d) standards, i.e., from Sections 111 and 712 of the EPAct of 1992, were denominated as follows:

Sec. 111(d)(7) Integrated Resource Planning (Sec. 111 of EPAct 1992)
Sec. 111(d)(8) Investments In Conservation And Demand Management (Sec. 111 of EPAct 1992)
Sec. 111(d)(9) Energy Efficiency Investments In Power Generation And Supply (Sec. 111 of EPAct 1992)
Sec. 111(d)(10) Consideration of the Effects of Wholesale Power Purchases On Utility Cost Of Capital; Consideration Of The Effects Of Leveraged Capital Structures on The Reliability Of Wholesale Power Sellers; And Assurance Of Adequate Fuel Supplies (Sec. 712 of EPAct 1992)

On January 7, 1993, the Staff filed a Motion To Establish A Docket And Schedule A Prehearing Conference relating to Section 712 of the EPAct of 1992 (i.e., Section 111(d)(10)), and the Commission established Case No. EO-93-218. The Staff submitted direct and rebuttal testimony of four witnesses (a financial analyst, an economist, an engineer and an accountant).

The signatory parties stipulated and recommended that the Commission make the determination that it is inappropriate and unnecessary to adopt generic standards or procedures regarding this issue, that instead this issue properly is reviewed on a case-by-case basis and that opportunities already exist for such review. On October 12, 1993, the Commission issued a Report And Order approving and adopting the Nonunanimous Stipulation And Agreement. The Report And Order states in part as follows:

> On February 19, 1993, as ordered by the Commission, a prehearing conference was convened. On March 3, 1993 the parties submitted to the Commission a memorandum of recommendations resulting from the prehearing conference. . . . On March 15, 1993, an issues workshop was held by the parties and from that workshop the parties filed on April 2, 1993 with the Commission a Composite List Of Issues. On May 18, 1993, direct testimony was filed by the following parties: Staff, UE, KCPL, MPS, EDE, SJLP, Anheuser-Busch, et al., Cogentrix, and Destec. . . . Rebuttal testimony was filed on June 8, 1993 by the following parties: Staff, KCPL, MPS, SJLP, Anheuser-Busch, et al., Cogentrix, and Destec. . . . On June 28, 1993 a Nonunanimous Stipulation And Agreement was filed with the Commission with only one party being a nonsignatory, Laclede Gas Company. On July 6, 1993 an evidentiary hearing was conducted in the Commission's hearing room located on the fifth floor of the Truman Building in Jefferson City, Missouri, where the Nonunanimous Stipulation And Agreement was submitted to the Commission . . . No party requested cross-examination of any witness . . .

In the Matter of the Investigation of the Section 712 Standards of the Energy Policy Act of 1992, Case No. EO-93-218, Report And Order, 2 Mo.P.S.C.3d 390, 392-93 (1993).

On January 19, 1993, the Commission issued an Order establishing Case No. EO-93-222 to address matters raised by Section 111 of the EPAct of 1992 (i.e., Sections 111(d)(7), (8), and (9)) as it related to the Commission's recently enacted Electric Resource Planning Rules, 4 CSR 240-22.010-.080, promulgated in Case No. EX-92-299 and, tangentially, in Case No. OX-92-3000, respecting the Commission's promotional practices rules, 4CSR 240-14.010, et seq. A unanimous Stipulation And Agreement was filed in which the parties agreed that the Commission had considered and implemented, at least in part, new standards Sections 111(d)(7), (8) and (9). On April 9, 1993, the Commission issued an Order Approving Stipulation And Agreement. (Order not printed in Commission's Bound Volumes).

B. <u>Gas Section 115 of EPAct 1992 – New Section 303(b) PURPA Standards and Gas Resource Planning Rules</u>

Section 115 of the EPAct of 1992 added Section 303(b)(3) Integrated Resource Planning and Section 303(b)(4) Investments In Conservation And Demand Management. On November 30, 1993, the Staff filed a motion requesting that the Commission establish a docket and schedule an early prehearing conference to consider whether to adopt the new natural gas standards. The Commission created Case No. GO-94-171 and scheduled an early prehearing conference. On February 15, 1994, a unanimous Stipulation And Agreement was filed in Case No. GO-94-171 in which the parties agreed that a rulemaking proceeding should commence in 1994 to address integrated resource planning for natural gas distribution companies, conservation and demand management and attendant considerations. On March 4, 1994, the Commission issued an Order Approving Stipulation And Agreement in which it agreed that compliance with the requirements of Section 303 was met by Case Nos. EX-92-299 and OX-92-3000, the instant docket and the consideration later that year of a proposed integrated resource planning rulemaking for natural gas. *In the Matter of the Investigation of the Section 115 Standards of the Energy Policy Act of 1992*, Case No. GO-94-171, Order Approving Stipulation And Agreement, 3 Mo.P.S.C.3d 13 (1994).

Subsequently, on April 24, 1995, a group of gas utilities filed a Motion To Determine The Need For Integrated Resource Planning Rules For Gas Utilities creating Case No. GO-95-329. On June 2, 1995, the Commission issued an Order in Case No. GO-95-329 in which it cancelled workshops and all other efforts by the Staff to proceed with the preparation of integrated resource planning rules for gas utilities, and stated that it would reconsider the necessity of such rules after the final first-round electric utility integrated resource planning filing was completed and approved. On June 16, 1995, the Commission issued an Order Denying Motion in which the Commission held, among other things, that the Public Counsel "presented no reason, and no reason is apparent, why the Commission would now be out of compliance with Section 115 of the Energy Policy Act or of Section 303 of PURPA." By proceedings in Case No. EO-99-365 and Case No. EO-99-544, various utilities first sought to have the Commission rescind Chapter 22 and then obtained the granting of variances from Chapter 22.